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11:54 AM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards Into Procurement Policies.	)))))	R. 06-04-009 (Filed April 13, 2006)

BEFORE THE CALIFORNIA ENERGY COMMISSION

In The Matter Of, AB 32 Implementation – Greenhouse Gas Emissions.	)))))	Docket 07-OIIP-01

PETITION FOR MODIFICATION OF DECISION NO. 07-01-039 OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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Dated: **January 28, 2008**

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Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("CPUC"), Southern California Edison Company ("SCE") hereby petitions the CPUC for modification of Decision No. 07-01-039 ("D.07-01-039" or "EPS Decision"), issued January 29, 2007. Through this petition, SCE urges the CPUC to recognize that SCE's continued legal obligations regarding Four Corners Generating Station do not fall under the category of "covered procurements" set out by the EPS Decision for CPUC-jurisdictional entities. In support of its petition, SCE herein sets forth factual background regarding the agreements that require its financial contributions to the Four Corners Generating Station and the problem posed by specific language in the EPS Decision.

I.

BACKGROUND

In January 2007, the CPUC adopted the EPS Decision pursuant to Senate Bill ("SB") 1368. That legislation directed the CPUC to establish a greenhouse gas ("GHG") emissions performance standard ("EPS") for baseload generation used by load-serving entities ("LSEs").[1] In keeping with the timing set out by SB 1368, the CPUC, through a rulemaking and in consultation with the California Energy Commission ("CEC") and the California Air Resources Board ("CARB"), adopted D.07-01-039.

Although the EPS Decision defined a standard that extended to LSE investment in retained generation which would (1) extend the life of one or more units of an existing baseload powerplant for five years or more, or (2) result in a net increase in the existing rated capacity of the powerplant, or (3) be designed and intended to convert a non-baseload plant to a baseload plant, the EPS Decision failed to address SCE's stated concern that the EPS Decision's specific language could be applied in a manner that would impair SCE's ability to fulfill the financial obligations it had undertaken when it executed various agreements which made SCE a co-owner of units 4 and 5 of Four Corners Generating Station ("Four Corners"). As noted in the sections below, application of the EPS Decision to preclude SCE's future investment in Four Corners will conflict with SCE's contractual obligation to financially support Four Corners, contravene the EPS Decision's stated intention, and harm SCE and its ratepayers.

A. The Terms of the Four Corners Agreements

SCE maintains a 48% co-tenancy interest in Four Corners.[2] SCE's rights and obligations with regard to Four Corners are set forth in various agreements.[3] Under the Agreements, SCE is contractually obligated "for the expenditures incurred for authorized Capital Additions, Capital Betterment, and Capital

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[1] Senate Bill 1368, Legislative Counsel's Digest, p. 2.

[2] Four Corners' other co-owners are Arizona Public Service Company, El Paso Electric Company, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, and Tucson Gas & Electric Company. SCE does not have an ownership share in Units 1-3 at Four Corners.

[3] These agreements include: the Co-Tenancy Agreement, the Operating Agreement, a Section 323 Grant, a New Lease, a Construction Agreement, an Additional Fuel Agreement, a Conditional Partial Assignment, an Ash Disposal Agreement, a Unit Tripping Agreement, a Recorded Memorandum, an Agreement to Purchase and Sell Undivided Interest in the Reserve Auxiliary Power Source, and an Exchange Agreement (collectively, "the Agreements").

Replacements in the same percentages as its percentage ownership therein . . . ."[4] If SCE does not pay its share of such expenditures, it will not receive power from Four Corners, but will remain liable for unpaid costs.[5]

Specifically, "while said default is continuing, all of the non-defaulting Participants may, by written notice to all Participants, suspend the right of the defaulting Participant to receive all or a part of its capacity entitlement by reducing the amount of energy generation of the Four Corners Project by a part or all of the capacity entitlement of the defaulting Participant . . . ."[6] During the period of such default, the non-defaulting co-owners would bear the costs of operating Four Corners, but SCE would be liable for all the costs it would have been required to fund, in addition to other default related costs and expenses involved in operating Four Corners during the period of SCE's default.[7]

B. SCE's Future Financial Obligation

Since the EPS Decision's adoption, SCE has filed General Rate Case Application No. 07-11-011 ("GRC"). In its GRC, SCE requests rate recovery of $178,593,000 to cover its share of capital expenditures at Four Corners. The capital projects for which SCE seeks rate recovery extend from 2007 through 2011 and are intended to sustain plant reliability, assure continued compliance with increasingly stringent environmental regulations and permits, and ensure continued compliance with workplace safety objectives.[8] Among the expenditures included in the GRC are replacement of the Unit 5 lower boiler waterwall tubes, replacement of secondary superheater and pendant reheater tube assemblies, and replacement of the High Pressure Turbine steam path.[9] These expenditures, and others outlined in the Four Corner Testimony, will also help ensure that Four Corners retains some residual value if SCE

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4 *See* Section 15.3 of the Operating Agreement. A copy of this Section is attached as Exhibit A to the Declaration of Laura I. Genao, attached hereto as Appendix A ("Genao Declaration").

5 Section 20.5 of the Co-Tenancy Agreement. A copy of the Section is attached as Exhibit B to the Genao Declaration.

6 *Id.*

7 Genao Declaration, Exhibit B, Section 20.5.3.

8 "2009 General Rate Case, Generation, Volume 7, Chapters X-XIII," p. 3. SCE will not list the specifics of each individual item for which it has requested GRC funding in this petition, however, each of those items is listed and described in greater details in SCE's "2009 General Rate Case, Generation, Volume 7, Chapters X-XIII," served November 19, 2007 ("Four Corners Testimony"), p. 3. A copy of this testimony is attached as Exhibit C to the Genao Declaration.

9 Four Corners Testimony, p. 4.

ultimately divests its share of the power plant when the Agreements' current term expires in 2016.[10] Each of the specific expenditures for which SCE seeks approval is documented at length in the testimony served with the GRC application.[11] Additionally, although SCE has not yet quantified the costs of investments required to safely and reliably maintain Four Corners beyond 2011, SCE anticipates that such expenses will be required.

C. SCE's Previous Request for Clarification

The aforementioned contractual arrangement for Four Corners concerned SCE when the CPUC contemplated adoption of a Proposed Decision ("PD") that defined "covered procurements" to include "[n]ew investments in the LSE's own existing, non-CCGT baseload powerplants that are: 1) intended to extend the life of one or more units by five years or more, 2) result in a net increase in the rated capacity of the powerplant, or 3) intended to convert a non-baseload plant to a baseload plant."[12] That PD included language which stated that "new ownership investments" were defined to include "any investment that is intended to extend the life of one or more units of an existing baseload powerplant for five years or more, or results in a net increase in the existing rated capacity of that powerplant."[13] In its comments on the PD, SCE raised the concern that such direction could be construed to preclude SCE from fulfilling its obligations under existing contracts with third-party co-owners of a baseload powerplant for financial investments required to maintain the powerplant for the term of the existing contract or the intended life of the plant.[14] Specifically, SCE envisioned a situation where it would be barred from fulfilling its contractual obligation to contribute financially to replacement of equipment items that would arguably extend the life of the plant by at least five years.[15]

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[10] The Agreements' current term extends through 2016. *See* Co-Tenancy Agreement, Section 21.1. A copy of this Section is attached as Exhibit D to the Genao Declaration.

[11] *See* Four Corners Testimony, pp. 12-61.

[12] Proposed Decision, issued December 13, 2006, Attachment 7, pp. 2-3.

[13] PD, p. 48.

[14] *See* Comments of SCE on the Proposed Decision of President Peevey and ALJ Gottstein, filed January 2, 2007, pp. 9-10.

[15] *See* Comments of SCE on the Proposed Decision of President Peevey and ALJ Gottstein, filed January 2, 2007, p. 10.

Despite SCE's concerns, the CPUC adopted the EPS Decision and rejected SCE's requested relief of an exemption for "financial contributions required by contracts with third-party co-owners."[16] The CPUC did so because it did not believe it had enough evidence in the record upon which to grant SCE's request.[17] Instead, the EPS Decision directed SCE to file an application or petition for modification requesting appropriate relief if it felt that the EPS would prevent it from complying with its contractual obligations at Four Corners.[18] SCE does so now.

II.

THE EPS DECISION SHOULD BE MODIFIED TO EXPLICITLY EXCLUDE FOUR CORNERS DURING ITS CURRENT TERM

As currently adopted, D.07-01-039 applies the EPS to, among other things, new utility investment in retained generation that is intended to extend the life of one or more units by five years or more or which results in a net increase in the existing rated capacity of that powerplant.[19] By its terms, the EPS Decision implicates Four Corners, even though the clear intent of the EPS Decision was not to "subject[] the millions of dollars in the LSEs already built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments."[20] To reconcile the EPS Decision's language with its intent, SCE urges the CPUC to modify the EPS Decision to find that financial contributions required under preexisting contractual obligations for generating units owned jointly with third parties are not "covered procurements" under the EPS. Such a modification will allow SCE to maintain the safety and reliability of Four Corners, as well as minimize the costs of compliance with the EPS to SCE and its electricity customers.

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[16] D.07-01-039, p. 46.
[17] D.07-01-039, pp. 45-46.
[18] D.07-01-039, p. 46.
[19] D.07-01-039, p. 53.
[20] D.07-01-039, FOF 220(c).

A. <u>As Written, the EPS Decision May Prevent SCE From Meeting its Existing Financial Obligations</u>

The text of the EPS Decision defines an EPS trigger that covers "new ownership investments in baseload generation." Such ownership investments are described as, among other things, "new investments in the LSE's own existing, non-CCGT baseload powerplants that are: (i) designed and intended to increase the life of one or more units by five years or more."[21] Without further clarification, this language triggers the EPS for SCE's required future investment in Four Corners.

By its terms, the EPS Decision triggers the EPS for Four Corners because SCE's contemplated future investments are intended to extend the plant's life through 2016[22] and the plant is a non-combined cycle gas turbine baseload powerplant.[23] Under California law, an LSE is prohibited from entering into the type of long-term financial commitments the CPUC has defined within the EPS Decision if those commitments do not comply with the EPS.[24] Accordingly, without modification of the EPS Decision or a reliability or "extraordinary circumstances" exception, SCE cannot make future investment in Four Corners.[25]

Application of the EPS trigger to Four Corners will preclude SCE from complying with its contractual obligation to fund required capital investment under the Agreements. As noted in Section I.A, above, if SCE fails to fund its contractual share of the expenditures for Four Corners, SCE will lose its right to power generated by Four Corners (SCE's share of Four Corners' output is approximately 750 MW), but will continue to be contractually liable for the financial obligation to provide payment for its portion of Four Corners' capital expenditures and other costs.[26]

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21 D.07-01-038, Conclusions of Law ("COL") 11.
22 *See* Four Corners Testimony, p. 3.
23 *See* Four Corners Testimony, p. 2.
24 *See* Cal. Pub. Util. Code, Section 341(a).
25 *See* D.07-01-039, Attachment 7, pp. 13, 17.
26 Genao Declaration, Ex. B, Section 20.5.

B. The EPS Decision Was Not Intended to Prevent SCE From Meeting Its Existing Financial Obligations

Although the EPS Decision's specific terms appear to preclude SCE from making the required capital expenditures for Four Corners, the CPUC's stated intention for the EPS does not match the decision's language. Instead, the CPUC's statements of intention with regard to the EPS indicate that it wished to exempt pre-existing co-ownership agreements for units such as Four Corners. Specific instances where the stated intention behind the adopted EPS definition does not match up to the EPS Decision's explicit order are set forth below.

First, the CPUC clearly stated that it adopted an EPS that would "not subject[] the millions of dollars in the LSE's already-built facilities to a standard that is being developed to prevent backsliding in LSE decisions made for future investments."[27] Precluding SCE from making the required financial investments in Four Corners would do exactly what the CPUC did not want to do—subject the millions of dollars SCE has already spent on preparing Four Corners to serve SCE's customers throughout its current term to a standard intended to affect future investment decisions.

Second, although the text of the EPS Decision "defin[es] the EPS trigger to include LSE investments in retained generation intended to (1) extend the life of one or more units of an existing busload [sic] powerplant for five years or more,"[28] the CPUC's stated intention for such a definition was to prevent adoption of an EPS trigger which would have required that every replacement of equipment or addition of pollution control equipment would trigger compliance with the EPS regardless of whether the plant, its operations, and its emissions remained essentially unchanged.[29] Questioning SCE's ability to make the required capital investment in Four Corners essentially does exactly what the CPUC did not want to do, it requires every piece of SCE's capital expenditures to be assessed for EPS compliance.

Third, the CPUC's desire was to adopt an EPS trigger that only captured changes to existing retained generation that fundamentally altered the way in which an existing baseload powerplant operates. Evidence

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[27] D.07-01-031, FOF 220(c).
[28] D.07-01-039, FOF 33.
[29] D.07-01-039, FOF 31.

of this is found in the CPUC's statement that it "defin[ed] the EPS trigger in this manner [to] cover[] 'repowering' as the term is generally used in the industry, which is the type of investment in retained generation that staff and most parties agree should be included under the definition of new ownership investments."[30] As noted in the Four Corners Testimony, SCE's planned capital investment is not a repowering or other type of investment intended to fundamentally change the manner in which Four Corners currently operates.

Lastly, evidence of the CPUC's intention to exclude ownership arrangements like the one SCE has for Four Corners is found in the EPS Decision's statement that covered procurements were defined in a manner which "[f]ocuses compliance on the types of facilities over which the LSE has the most discretion and choice, thereby minimizing the cost of compliance to the LSE and its electricity customers."[31] SCE's financial obligation with regard to Four Corners is not one over which it has much discretion or choice. The Agreements have been effective for almost 42 years and, as discussed above, contain strict default provisions that will be triggered if SCE fails to make required financial contributions. Further, as discussed further below, the loss of electrical capacity and energy that will result if SCE cannot meet its financial obligations will harm SCE and its ratepayers in a manner that seems contrary to the CPUC's intention for the EPS.

Because the EPS Decision does not appear to have been intended to cover ownership interests such as SCE's in Four Corners, SCE requests that the EPS Decision be modified to reflect that the EPS does not apply to financial contributions required by existing contracts with third parties for baseload generation used by an LSE to serve its load. The EPS Decision can be modified to exclude its applicability to arrangements such as Four Corners by inserting the following language into the definition of "Covered Procurements" set forth in Attachment 7:

> **Except for financial contributions required by existing contractual agreements (effective prior to January 29, 2007), n**ew investments in the LSE's own existing, non-CCGT baseload powerplants that are: 1) intended to extend the life of one or more units by five years or more, 2) result in a net

[30] D.07-01-039, FOF 34.
[31] D.07-01-039, FOF 220(b)(iii).

> increase in the rated capacity of the powerplant, or 3) intended to convert a non-baseload plant to a baseload plant, ...

C. SCE's Ratepayers Will Experience Significant Capacity Shortages and Financial Impacts if SCE Is Barred From Making its Required Financial Obligations

As noted in the Four Corners Testimony, resources from Four Corners make up approximately 720 MW of SCE's resource portfolio. Any sudden decision which would prevent SCE from being able to rely on that generation in the manner which it had planned, and approved by the CPUC through the long-term procurement planning process, would severely affect SCE and its customers. In order to avoid such an outcome, the CPUC should modify the EPS Decision as set forth above.

Among the primary effects denial of SCE's access to this resource would have would be a financial effect. Without Four Corners in the bundled customer portfolio, SCE must replace the energy it would have otherwise received from that plant. Using a conservative estimate of $40/MWh as the difference between the replacement cost of energy and the avoided production cost from Four Corners, it would cost SCE's customers $189 million in incremental replacement costs on an annual basis, assuming a 75% capacity factor.[32] Moreover, this amount does not include the Resource Adequacy value of SCE's Four Corners capacity, which could equate to an additional $29 million in replacement costs using the Commission's $40/kW-year capacity valve threshold for local area market power assessments.[33] Thus, the potential loss of energy and capacity from Four Corners could easily cost SCE's customers close to $220 million or more per year depending on market conditions.

Because the CPUC's intention was to implement an EPS that recognized, among other things, prior investment and consumer cost, SCE urges the CPUC to modify the EPS Decision as set forth above. Doing so will protect SCE and its ratepayers, as well as align the CPUC's stated intentions for the EPS with the text of the EPS Decision.

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32 Derived as follows: $40/MWh * 750 MW per unit * 2 units * SCE's 48% Ownership Share * 8760 hours * 75% capacity factor.

33 Derived as follows: $40/kW-year * 750 MW * 2 units * SCE's 48% Ownership share.

III.

CONCLUSION

As SCE has noted above, the EPS Decision's explicit language fails to match up with the CPUC's apparent intention with regard to required financial contributions for co-owned retained generation under current contract. In order to eliminate the confusion arising from such conflicting language, the EPS Decision should be modified to reflect the intention to exempt existing financial contributions under co-ownership arrangements with third parties for baseload units.

Respectfully submitted,

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January 28, 2008

Appendix A

DECLARATION OF LAURA I. GENAO

I, Laura Genao, have personal knowledge of the facts contained herein and if called to testify under oath could and would testify as follows:

1. I have been continually employed by Southern California Edison Company ("SCE") from December 2002 to date. My present capacity is as an Attorney in the law department. I am duly authorized to practice law before the Courts of the State of California and the California Public Utilities Commission ("CPUC"). My duties include representing SCE in connection with Rulemaking 06-04-009. I make this declaration in support of SCE's Petition for Modification of Decision No. 07-01-039.
2. Attached hereto as Exhibit A is a true and correct copy of Section 15.3 of the Operating Agreement for Four Corners Generating Station.
3. Attached as Exhibit B is a true and correct copy of Section 20.5 of the Co-Tenancy Agreement for Four Corners Generating Station.
4. Attached as Exhibit C is a true and correct copy of SCE's "2009 General Rate Case, Generation, Volume 7, Chapters X-XIII."
5. Attached as Exhibit D is a true and correct copy of Section 21.1 of the Co-Tenancy Agreement for Four Corners Generating Station.

I declare the foregoing to be true and correct under penalty of perjury under the laws of the State of California. Executed this 28th day of January, 2008.

L Genao

Laura I. Genao

Exhibit A

Participants, if possible, within thirty (30) days following a request by the Operating Agent.

14.6 The Engineering and Operating Committee may at any time during the year approve revisions to the annual capital expenditures budget, annual manpower budget, and the annual operating and maintenance budget for the Operating Work.

15. CAPITAL ADDITIONS CAPITAL BETTERMENTS AND CAPITAL REPLACEMENTS:

15.1 All Capital Additions, Capital Betterments and Capital Replacements, and a contingency allowance for capital expenditures if necessitated by an Operating Emergency shall be included in the annual capital expenditures budget.

15.2 The Engineering and Operating Committee may authorize Capital Additions, Capital Betterments, and Capital Replacements not included in the annual capital expenditures budget; provided, that such Capital Additions, Capital Betterments, and Capital Replacements shall not exceed the sum of Three Hundred Thousand Dollars ($300,000.00) for each Capital Addition, Capital Betterment, or Capital Replacement, unless such Capital Addition, Capital Betterment, or Capital Replacement is also authorized by the Coordination Committee.

15.3 Each Participant shall be obligated for expenditures incurred for authorized Capital Additions, Capital Betterments and Capital Replacements in the same percentages as its percentage ownership therein, and its rights, titles and interests therein shall be as set forth in Sections 6, 7, or 15, whichever is applicable, of the Co-Tenancy Agreement as amended.

Exhibit B

shall specify the reasons upon which the protest is based. Copies of such protest shall be mailed by such Participant to all other Participants. Payments not made under protest shall be deemed to be correct, except to the extent that periodic or annual audits may reveal over or under payment by Participants or may necessitate adjustments. In the event it is determined by arbitration, pursuant to the provisions of this Co-Tenancy Agreement or otherwise, that the protesting Participant is entitled to a refund of all or any portion of a disputed payment or payments, or is entitled to the reasonable equivalent in money of non-monetary performance of a disputed obligation theretofore made, then, upon such determination, the non-protesting Participants shall pay such amount to the protesting Participant, together with interest thereon at the rate of six per cent (6%) per annum from the date of payment or of the performance of a disputed obligation to the date of reimbursement. Reimbursement of the amount so paid shall be made by the non-protesting Participants in the ratio of their respective capacity entitlements to the total capacity entitlement of all non-protesting Participants.

20.5 In the event a default by any Participant in the payment or performance of any obligation under the Project Agreements shall continue for a period of six (6) months or more without having been cured by the defaulting Participant or without such Participant having commenced and continued action in good faith to cure such default, or in the event the question of whether an act of default exists is the subject of arbitration and such default continues for a period of six (6) months following a final determination by the arbitrators (or a Court of competent jurisdiction as provided in Section 19.9 hereof) that an act of default exists and the defaulting Participant has failed to cure such default or to commence such action during said six (6) month period, then, at any time thereafter and while said default is continuing, all of the non-defaulting

Participants may, by written notice to all Participants, suspend the right of the defaulting Participant to receive all or a part of its capacity entitlement by reducing the amount of energy generation of the Four Corners Project by a part or all of the capacity entitlement of the defaulting Participant, in which event:

20.5.1 The non-defaulting Participants shall instruct the Operating Agent in writing to suspend and the Operating Agent shall thereupon suspend, delivery of all or the specified part of the defaulting Participant's capacity entitlement.

20.5.2 During the period that such decrease in generation is in effect, the non-defaulting Participants shall bear all of the operation and maintenance costs, fuel costs, insurance costs and other expenses otherwise payable by the defaulting Participant under the Operating Agreement in the ratio of their respective capacity entitlements to the total capacity entitlements of all non-defaulting Participants.

20.5.3 The defaulting Participant shall be liable to the non-defaulting Participants (in the proportion that the capacity entitlement of each non-defaulting Participant bears to the capacity entitlements of all non-defaulting Participants) for all costs incurred by such non-defaulting Participants pursuant to Section 20.5.2 hereof and for all excess costs and expenses involved in operating the Four Corners Project at a reduced level of generation brought about by the reduction of the capacity entitlement of the defaulting Participant. The proceeds paid by any defaulting Participant to remedy any such default shall be distributed to the non-defaulting Participants in the ratio of their respective capacity entitlements to the total capacity entitlements of all non-defaulting Participants.

Exhibit C

Application No.:	
Exhibit No.:	SCE-02, Vol. 7 Ch. X-XIII
Witnesses:	P. Phelan T. Ware

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

2009 General Rate Case

Generation
Volume 7 – Coal Capital Expenditures
Chapters X – XIII

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 2007

SUMMARY

SCE-02, Volume 7

COAL CAPITAL

- Four Corners will provide 720 MW (SCE Share) of coal-fired generating output during 2009 through 2011.
- Four Corners O&M Test Year 2009 Expense forecast is $39 million.
- Four Corners Capital Expenditure forecast for 2007 - 2011 is $179 million.
- Plans for the final disposition of Mohave are currently being formulated, continued rate treatment using the Mohave Balancing Account is proposed, and it is currently assumed the plant will be decommissioned by 2010 at a cost of $56 million (SCE share).

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X.

INTRODUCTION TO SCE'S CAPITAL EXPENDITURES PLAN FOR COAL-FIRED GENERATING STATIONS

This Part 2 of SCE 2, Volume 7, Chapter IX Section A and B describes the capital expenditure requirements for SCE's ownership interest in Four Corners Generating Station Units 4 and 5. SCE developed the Four Corners capital forecast contained in this Exhibit based on plant conditions that are known at this time. Total capital expenditures required for Four Corners for projects going into service during 2007 through 2011 (SCE share of costs) are $178.593 million. Individual expenditures of $1 million or more represent 80 percent of this estimate and are described herein. Projects less than $1 million each are also briefly discussed herein. Our work papers contain additional information on essentially all of these projects.

In Chapter XI of this Volume 7, we describe the rigorous process we use to identify, select, justify and approve capital expenditures for Four Corners. We provide a table recapping all expenditures in Appendix A and provide a brief description of each expenditure line item. We provide additional descriptions and justification statements in the work papers that accompany this volume.

This Part 2 of SCE 2, Volume 7 also describes our $56 million (SCE share) capital expenditure to decommission the out-of-service Mohave Generating Station. We currently forecast that Mohave will be decommissioned by 2010, but the decision to proceed with decommissioning has not yet been made by the plant owners. The final schedule will depend on how quickly the decision to proceed with decommissioning is made, and on the final agreed-upon decommissioning scope of work. As the exact scope of work for decommissioning is still under review, it is difficult to precisely estimate the actual ultimate decommissioning cost. Therefore, SCE proposes to continue the Mohave Balancing Account regulatory mechanism approved in the 2006 GRC to reconcile our final actual decommissioning expenditures, and to reconcile related Mohave site management O&M expenses which are discussed in Part 1 of this volume.

A. SCE's Four Corners Capital Expenditures Address Key Generating Station Performance Objectives

SCE's performance objectives for Mohave and Four Corners include personnel safety, environmental responsibility, production reliability, prudent cost management, and fuel-efficient operation. These objectives, which we discuss in more detail in Chapter III of Part I of this Volume 7, are the basis for our capital expenditures plan. People with the most knowledge and experience with these complex coal-fired generating stations evaluate plant performance, determine what improvements are required to sustain and improve performance, obtain a determination regarding expense or capitalization of the expenditure and rigorously assess the merits of the expenditure using the approach we discuss in Chapter XI.

B. SCE's Four Corners Capital Expenditures During 2007 Through 2011 Do Not Conflict With The Commission's Rules On Greenhouse Gas Emissions

D.07-01-039, dated January 25, 2007, in R.06-04-009 on greenhouse gas (GHG) emissions standards, adopted an emissions performance standard or "EPS" to provide a "near-term" bridge of compliance with SB 1368.[1] The EPS limits power plant emissions rate to no higher than the emissions rate of a CCGT base-load power plant. All existing coal plants, including Four Corners, are unable to meet the EPS emissions standards. Conclusion of Law No. 11(c) to D.07-01-039 sets forth the type of capital investment in non-CCGT base-load power plants, like Four Corners, that require compliance with the EPS. These capital investments include those that are:

> (i) designed and intended to extend the life of one or more units by five years or more;
>
> (ii) result in a net increase in the rated capacity of the powerplant. . . .[2]

In this General Rate Case, SCE requests recovery of capital investment in the Four Corners that will <u>not</u>: (1) extend its life beyond the end of the current operating life; or (2) result in a net increase in

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[1] SB 1368 requires all new base load commitment to have an EPS no higher than the rate of a CCGT baseload powerplant.

[2] D.07-01-039, dated January 25, 2007, Conclusion of Law No. 11, p.265.

the rated capacity of the power plant. Therefore, these investments do not result in a need to apply the EPS to Four Corners.

SCE has a contractual commitment to the other owners of Four Corners to fund necessary capital requirements. The Operating Agreement for the Four Corners Projects requires at Section 15.3 that:

> Each Participant shall be obligated for the expenditures incurred for authorized Capital Additions, Capital Betterment, and Capital Replacements in the same percentages as its percentage ownership therein. . . .

If SCE does not pay its share of such expenditures, the Four Corners Projects Co-Tenancy Agreements provides in Section 20.5 that SCE will not receive any Four Corners power,[3] but will remain liable for the costs not paid.

The Four Corners capital expenditures forecast in this docket will assure reliable, safe and legally compliant operation through 2016, which is the end of the current Operating and Co-Tenancy Agreement for Four Corners. They will also help ensure that Four Corners retains some residual value if SCE ultimately divests its share of the power plant.

C. The Level Of Forecast Capital Expenditures At Four Corners Is Reasonable And Important To SCE's Customers

Table X-1 depicts the recorded and forecast capital expenditures (SCE share) at Four Corners for projects which go into operation during the years 2007 through 2011. These are categorized by their primary business reason; i.e., sustaining plant reliability, assuring continued compliance with increasingly stringent environmental regulations and permits, and continued compliance with our workplace safety objectives.

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[3] Appendix C contains the full text of Section 20.5 of the Co-Tenancy Agreement.

Table X-1
Capital Expenditures At Coal-fired Generating Stations
2007 – 2011

Purpose	Total SCE Share	$1,000 - Nominal 100% Share						
		Prior	2007	2008	2009	2010	2011	Total
Reliability	132,645	12,794	40,033	52,417	64,572	78,397	43,819	292,032
Environmental	42,477	3,655	18,284	14,048	20,962	19,728	13,355	90,032
Safety	3,471	1,121	782	263	1,600	2,200	3,000	8,966
TOTAL	178,593	17,570	59,099	66,728	87,134	100,325	60,174	391,030

The Four Corners capital expenditures during these five years are largely driven by major overhauls conducted during years 2008 and 2010. The cash flows depicted above include cost for materials in the years prior to the 2008 and 2010 overhaul years. These overhaul expenditures include capital for turbine/generator components, lower boiler waterwall tube replacements, boiler reheater and outlet header replacements and other major capitalized maintenance expenditures such as S02 controls required to maintain station environmental regulatory compliance.

The overall increasing trend of required Four Corners capital expenditures is indicative of the effects of obsolescence, aging, and severe service conditions that we discuss in Chapter IV. Specifically, the substantial expenditures forecast for 2007 and 2008 include replacement of the Unit 5 lower boiler waterwall tubes because of excessive tube wall thinning, replacement of the secondary superheater and pendant reheater tube assemblies that are becoming unreliable, and replacement of the High Pressure Turbine steam path. This work will be accomplished during the next scheduled major overhaul of Unit 5 in 2008 and is discussed in detail in Chapter IV. The Unit 4 overhaul planned for 2010 includes the needed replacement of many of these same equipment items. Our Capital forecast also reflects the increasingly stringent limits on our air pollution emission, particularly associated with a new Federal Implementation Plan.

In SCE 2, Volume 1 testimony, witness Richard Rosenblum states that SCE provides its customers their generation needs from a diverse generation portfolio that includes approximately 7 percent of energy produced by Four Corners Units 4 and 5.[4] Because Four Corners Units 4 and 5 operate as base load units, SCE must supply its customers with other sources of energy when Four Corners is out of service. Assuming a conservative replacement energy cost of $50 dollars per MWh, a single four-day forced outage[5] shutdown at Four Corners Unit 4 or Unit 5 costs SCE's customers $1.728 million in increased energy production costs.[6] Continued reliable energy production is important to our customers and the expenditures included in our forecast focus primarily on sustaining production performance, thus supporting the needs of our customers. We therefore believe the capital expenditures included in our forecast are important and reasonable for a number of reasons, including:

- Coal-fired electrical energy is economically attractive compared to other alternatives and represents an important source of fuel diversity protection for SCE's customers;
- Capital expenditures are necessary for continued operation of Four Corners and our plan addresses important performance objectives for this asset, which include personnel safety, environmental responsibility, production reliability, and thermal efficiency;
- SCE's capital expenditures address the effects of obsolescence, age-related deterioration, and accumulated effects of service conditions that adversely affect performance at this thirty-seven year old generating station;
- The capital expenditures included in our plan were forecast by people most knowledgeable about the Four Corners generating station, as described in Chapter XI;
- The individual capital expenditures at Four Corners are subject to rigorous review using objective criteria and are subject to several levels of review and approval prior to execution, as described in Chapter XI;
- Capital expenditures made at Four Corners are cost effective compared to the alternative of replacing power from Four Corners by some other source;

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4 SCE 2, Volume 1, Chapter I, including Figure I-I.

5 A forced outage occurs when the operating unit unexpectedly cannot generate megawatts.

6 Based on 750 MW x 48 percent SCE ownership x 24 hours x 4 days x $50 per MWh = $1.728 million.

- Capital expenditures are needed to assure reliable, safe and legally compliant operation through 2017, which is the end of the current Agreement among the Four Corners Units 4 and 5 co-owners;
- Capital expenditures during 2007 through 2011 will help ensure the residual value of Units 4 and 5, should SCE divest its share of this important power plant, because of the regulatory requirements of California concerning greenhouse gas emissions.

XI.

WE USE RIGOROUS CRITERIA IN THE SELECTION, JUSTIFICATION AND APPROVAL OF CAPITAL EXPENDITURES FOR COAL-FIRED GENERATING STATIONS

A. Personnel Most Knowledgeable Identify And Select Capital Expenditures That Support Our Performance Objectives For Four Corners

We briefly described in SCE-2, Volume 7, Part I Generation Coal O&M Chapter II Section D Arizona Public Service's (APS) safety, environmental compliance, reliability and thermal efficiency programs at Four Corners. APS's staff includes 20 engineers with over 260 years of combined industry experience. These knowledgeable personnel, along with the managers, supervisors, journeymen, and operators, operate and maintain the Four Corners plant and developed the capital expenditure forecasts for Four Corners.

SCE subject matter experts also reviewed the APS capital forecast. Our SCE experts include personnel with many years of operating, maintenance and engineering experience at fossil-fueled power plants, including coal-fired power plants which are similar to Four Corners. SCE personnel who review the proposed capital forecast, and propose changes to the APS proposed plan, do so based on their experience and their analysis of the data provided by APS. The review of our SCE subject matter experts validated that all capital expenditures presented herein are needed to sustain Four Corners historic level of reliability performance through the end of the plant's current life expectancy, or are needed to comply with safety and environmental regulatory requirements.

B. We Rigorously Evaluate Capital Expenditures Using Objective Criteria That Supports Ratepayer Interests

We conduct an economic analysis on capital expenditures that are designed to save costs (including replacement energy costs) or improve fuel efficiency.[7] The economic analysis determines the benefit-to-cost ratio (B/C) of the expenditure. All assumptions must be clearly stated and incorporate SCE economic factors, such as economic discount rates.

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[7] Expenditures required for employee safety or to assure that the generating station conforms to environmental or other laws or regulations do not rely on economic justification and do not require an economic analysis.

Economic analyses by nature are based on predictions. The accuracy of these predictions depends on the accuracy of cost estimates and on a wide variety of factors, such as escalation rates, projected capacity factors, and fuel costs. Theoretically, all expenditures with a B/C of greater than 1.0 are economically justified, because the benefits exceed the costs. The accuracy of the estimated costs and benefits, however, cannot always be ensured. Therefore, we generally require higher B/C ratios greater than 1.5, to increase the probability that justified expenditures remain viable, even if the projected savings are not fully realized. Should the B/C ratio be less than 1.0, the project is typically not approved, but might be revisited in the future should the situation change. Should the B/C ratio fall between 1.0 and 1.5, further review is performed to determine if the project should be approved, or if it should be deferred for re-evaluation at a later date.

C. <u>Four Corners Capital Expenditures Require Review And Approval By SCE Management And Participant Plant Owners</u>

Capital expenditures for Four Corners undergo a rigorous review process, which includes up to four levels of examination, scrutiny, and authorization. This process is as described below.

1. <u>Local Review</u>

Expenditure recommendations originate with the engineers, operators and maintenance specialists at Four Corners, whose analysis, experience and ideas for sustaining and improving plant performance are the basis for investment proposals. The plant's technical and management staff examine and prioritize all expenditure recommendations. The staff then documents the expenditure, and performs the initial economic review. The staff then adds these projects to APS's draft Long Range Capital Forecast for further review.

2. <u>SCE Power Production Department Review</u>

APS provides the draft long-range plan to each of the Co-owners prior to the August quarterly E&O Committee meeting. The August meeting is where the co-owners provide final review and approval of the capital and O&M budgets for the upcoming calendar year. To prepare for this meeting, the SCE Engineering & Operating representatives (who work in SCE's Power Production Department) then obtain any needed additional information and data about new projects, so that an SCE review of the proposed new projects can be performed. We apply our own SCE forecasts of future coal fuel costs, and other economic factors, in conducting this review. As described above for certain projects, we also seek technical input from subject matter experts within SCE (e.g., such as transformer experts in our Shop Services and Instrument Department).

3. SCE Corporate Review

Certain capital expenditures are subject to approval by SCE's Capital Review Team (CRT) and Utility Management Committee. The SCE Capital Review Team process is a formal and structured review procedure involving a decision panel of corporate officers that review proposed non-core capital expenditures with dollar thresholds of $1 million and $10 million respectively. SCE 7, Volume 1 discusses the composition, role, and operation of the CRT and Utility Management Committee Review By Four Corners Plant Owner Representatives.

4. E&O Committee Approval

Plant participant owner approval is the final stage of expenditure review. The Operating Agreement for Four Corners requires, as part of the overall plant budgeting process, that the Engineering and Operating Committee (E&O Committee) approve all capital expenditures at its regular August business meeting each year.[8] The plant E&O Committees, which include representatives from each Participant, are discussed in detail in Chapter II of Volume 7.

The Operating Agent presents the proposed capital budget item to the E&O Committee before the August meeting, and the owner representatives review the information and discuss the expenditures within their internal organizations and technical teams. If the E&O Committee approves the capital budget item, the expenditure becomes an approved budget item and work is allowed to proceed.

[8] Exceptions to this rule are sometimes required, and provisions in the Operating Agreements allow the Operating Agents to submit "mid-year" capital expenditure items for approval. Certain mid-year items require the approval of the E&O Committee and the Coordinating Committee representative. The Coordinating Committee includes an officer of each of the Participants.

D. We Maintain And Follow A Long-Range Plan And Cost Forecast For Our Capital Work

As the Operating Agent, APS maintains a Long-Range Capital Forecast. This forecast includes the annual budgets which have already been approved in their entirety (i.e., for the current year and for the upcoming calendar year). This forecast further includes projects which have been formally approved for future years beyond the immediate year in question. When materials need to be ordered well in advance of the capital work (i.e., a year or more before the work), then formal approval of such a future year's project is required so that those materials can be ordered. Such approval follows the process described above.

The APS Long-Range Capital Forecast also includes capital projects which are anticipated from two to five years from the present time, but have not yet been formally approved by the Participants. Such projects typically include capital maintenance work anticipated for the next major planned overhauls, similar anticipated capital projects needed to sustain station reliability and fuel efficiency not associated with major unit overhauls, and capital work needed to comply with anticipated or recently enacted regulations.

Our capital expenditure forecast is based on this long-range plan because it represents the best information available at the time of this filing.[9] The long range plan reflects plant conditions that are known and also includes expenditure forecasts for future years that are believed to be important, but are less understood and have not received a complete level of scrutiny or analysis. Accordingly, the accuracy of these long-range forecasts decreases the farther into the future that costs are being projected. The dynamics of operating large complex coal-fired generating stations in a business environment that undergoes constant change results in the potential for forecast volatility. Neither SCE nor APS have the staff or other resources required to precisely forecast every possible expenditure to be required years into the future.

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9 Before including forecast capital expenditures in this Volume 7, SCE engineers and managers reviewed all expenditures and worked with APS to validate the reasonableness of including expenditures contained in the APS plan in our forecast. Accordingly, not all expenditures presently forecast by APS are included in this Volume 7. Conversely, the SCE review determined that a few projects in the current APS plan will likely need to be accelerated, based on our current assessment of those projects. Those changes are also included in this Volume 7.

As described above, typically, the Operating Agent performs the more rigorous analysis one year in advance of the expenditure, but does not have the resources to perform this level of analysis beyond this shorter planning period. Therefore, the Long Range Capital Forecast must also include an appropriate level of funding which has not yet been fully defined or itemized. This funding is not allocated to any of the specifically listed projects, but rather is included to fund other projects which past experience has shown will arise as we move forward in time. Typically, at any moment in time, the Participants are aware of several potential future projects which might be required, but which are not yet far enough along in the project development process to be specifically listed in the Long Range Capital Forecast. These projects thereby represent some of the possible future candidates for which unallocated funding may be needed in the future. Experience has also shown that other capital needs do arise which must be addressed between rate cases and which are completely unforeseen at this time. The unallocated funding in the capital forecast is included to assure such needs can be addressed. More details regarding our forecast for unallocated future projects is presented in chapter XI.

XII.

CAPITAL EXPENDITURES REQUIRED FOR FOUR CORNERS GENERATING STATION

A. Introduction

There are a number of distinct groups of Four Corners assets, including those unique to Unit 4, those unique to Unit 5, those common to Units 4 and 5, and those common to all five generating units (Units 1-3 are solely owned by APS). Examples of the later category include administrative buildings, vehicles, cooling water lake, and portions of the switchyards. We provide descriptive information for Four Corners Generating Station in Chapter II and in Appendix B of this Volume 7. We discuss the SCE ownership share of each group of Four Corners assets in Chapter II.B.

The Four Corners assets are critical to the safe and reliable generation of electricity. Much of the Four Corners equipment has been in service in a very difficult service application, for over 30 years. Many Four Corners components also require refurbishment or replacement on a periodic basis. Much of this work can be performed only during periods when one or both generating units are out of service, such as occurs during regularly scheduled maintenance and overhaul outages. As the Operating Agent for Four Corners on behalf of the Four Corners Participants, APS regularly inspects and monitors the condition of the Four Corners assets. When required, equipment is scheduled for repair, overhaul, refurbishment, or replacement.

This Chapter XII addresses the capital expenditures required to meet our business objectives for Four Corners during the 2007 through 2011 Ratemaking Period. Our capital expenditure forecast for Four Corners includes expenditures that have been fully evaluated and some, as we discuss in Chapter X.C, that we believe to be important but that have not yet been fully engineered and formally approved by all plant owners. SCE uses the process described in Chapter XI to evaluate and approve Four Corners capital expenditures.

The total capital expenditures required to support Four Corners Generating Station Units 4 and 5 for projects placed in service during 2007 through 2011 is $391.030 million, of which SCE's share is $178.593 million. Capital expenditures required to support plant performance include those needed to sustain boiler reliability, such as replacement of the lower waterwall tubes in the Unit 5 boiler that are becoming unreliable; replacement of the Unit 5 1st and 2nd stage superheater tube assemblies; and replacement of the Unit 5 pendant reheater and steam collection headers that are beginning to fail. Other expenditures include replacement of turbine components that are no longer reliable, replacement of unreliable power transformers, and construction of a new landfill for disposal of plant wastes.

Table XII-2 includes a summary listing of all forecast capital expenditures required to support Four Corners for 2007 through 2011. We provide additional information on all individual projects in the workpapers.

Table XII-2
Four Corners Capital Projects Summary by Category

Purpose	Total SCE Share	$1,000 - Nominal 100% Share						
		Prior	2007	2008	2009	2010	2011	Total
Reliability	132,645	12,794	40,033	52,417	64,572	78,397	43,819	292,032
Environmental	42,477	3,655	18,284	14,048	20,962	19,728	13,355	90,032
Safety	3,471	1,121	782	263	1,600	2,200	3,000	8,966
TOTAL	178,593	17,570	59,099	66,728	87,134	100,325	60,174	391,030

As shown, we have categorized capital projects into three areas; specifically, Reliability, Environmental Compliance and Safety. The remaining chapters present additional information on the projects in each category as we focus on those projects which exceed $1.0 million (SCE share). We also briefly discuss projects which cost less than $1.0 million. More details on all projects can be found in our workpapers.

B. Reliability

Table XII-3 lists our reliability projects. As shown, these total $132.645 million (SCE share).

Table XII-3
Summary Table of Reliability Projects.

	RELIABILITY PROJECTS ($1,000 - Nominal)	In Service	100% Total	Fraction	SCE Share $1,000
1	HP TURBINE & CONTROLS REPL, U 5	2008	15,104	0.4800	7,250
2	HP TURBINE & CONTROLS REPL, U 4	2010	16,231	0.4800	7,791
3	MINOR OVERHAUL TURB REPAIRS, U 5	2011	6,534	0.4800	3,136
4	HP GENERATOR FIELD REWIND, U 4	2010	2,185	0.4800	1,049
5	LOWER BOILER REPLACEMENT, U 5	2008	18,495	0.4800	8,878
6	PENDANT RH & OUTLET HEADER REPL, U 5	2008	14,581	0.4800	6,999
7	PENDANT RH & OUTLET HEADER REPL, U 4	2010	18,981	0.4800	9,111
8	2ND STAGE PENDANT SUPHTR REPL, U 5	2008	11,187	0.4800	5,370
9	1ST STAGE PENDANT SUPHTR REPL, U 5	2011	13,320	0.4800	6,394
10	2ND STAGE PENDANT SUPHTR REPL, U 4	2010	14,081	0.4800	6,759
11	HORIZONTAL REHEAT BANK REPL, U 5	2011	6,310	0.4800	3,029
12	BOILER NOSE REPLACEMENT, U 4	2010	4,000	0.4800	1,920
13	BOILER NOSE REPLACEMENT, U 5	2011	4,190	0.4800	2,011
14	MAIN FLAME SCANNER UPGRADE, U 5	2008	2,379	0.4800	1,142
15	AIR PREHEATER H/C BASKET REPL, U 4	2010	2,180	0.4800	1,046
16	COAL PIPE REPL, U 5	2008	4,000	0.4800	1,920
17	COAL PIPE REPL, U 4	2010	8,867	0.4800	4,256
18	HP FEEDWATER HEATER REPL, U 4	2010	4,000	0.4800	1,920
19	PULVERIZER CAPACITY UPGRADE, U 4	2010	4,000	0.4800	1,920
20	GSU TRANSFORMER T633 & T634 REPL, U 5	2008	3,837	0.4800	1,842
21	GSU TRANSFORMER T631 REPL, U 4	2008	3,186	0.4800	1,529
22	GSU TRANSFORMER T629 REPL, U 4	2010	3,933	0.4800	1,888
23	UNDERGROUND CABLE REPLACEMENTS	annual	10,000	0.4800	4,800
24	PLANT PERIMETER SECURITY UPGRADE	2010	4,000	0.3476	1,390
25	COMPUTER PREDICTIVE/PERF TOOLS	annual	3,000	0.3476	1,043
26	BOTTOM ASH CONTROLS REPL, U 4&5	2009	2,267	0.4800	1,088
27	UNALLOCATED FUTURE PROJECTS	annual	37,768	0.4800	18,129
28	RELIABILITY PROJECTS < $1 MILLION EACH	various	53,415	various	19,036
	TOTAL RELIABILITY PROJECTS	various	292,032	various	132,645

1. <u>High Pressure Turbine Replacement and Controls Upgrade Unit 5</u>

This $15.104 million expenditure (of which SCE's share is $7.250 million) will replace the Unit 5 high-pressure turbine (HP turbine) section, including the HP rotor, blades, diaphragms, inner shell, and the turbine hydraulic controls system. The project also upgrades the turbine control system, including providing the ability to operate using full-arc steam admission. Additionally this project will replace first generation (1960's) turbine control valve electronic positional feedback field devices currently causing start-up delays. This work will be performed during the planned 2008 Unit 5 major overhaul.

The main turbines at Four Corners include an HP Turbine, IP Turbine and LP Turbine on each unit. The assembly of diaphragms, buckets (i.e., rotating blades) and associated casings, shafts, and sealing devices (called packing) that comprise the process flow components of a turbine is referred to as a "steam path." The existing HP Turbine was installed in the late 1960s. The HP Turbine processes steam at 1000 degrees and 3500 pounds per square inch and is subject to severe service. Over years of operation, the turbine components, including the rotors, rotor shafts, and shells, have been exposed to numerous startup and shutdown cycles, each of which has taken some of the life out of the equipment. APS conducts overhauls of the HP Turbine and other turbines at intervals of approximately 6 years; therefore, this equipment has been disassembled and reassembled numerous times.

During the most recent overhaul that was completed in 2002, the HP Turbine lower inner shell was found to be cracked and required extensive repair. The crack was over 40 inches long and as deep as 3 inches. The HP Turbines at Four Corners will continue to experience an increasing level of problems and replacement of this equipment will be required if the plant is to continue to operate through the end of its current expected life.

Since the time Four Corners was constructed, the technology and design of these machines has advanced to a point that significant benefits can be derived from upgrading to a modern configuration. Most significant among these benefits is the manner in which the thermal energy in the steam is converted into mechanical energy at the outlet shaft. These benefits result in improved machine efficiency. This efficiency improvement provides a decrease in fuel consumption for the same level of power output.

This expenditure includes replacement and upgrade of the high-pressure steam path, including new turbine inner shells and a new high efficiency rotor with increased number of stages and smaller wheel diameters to optimize the steam path. Also included is a new solid particle erosion (SPE) resistant single flow nozzle, replacement of the mechanical hydraulic control system, and control valves modification to allow full-arc steam admission. Full-arc admission reduces the level of thermal fatigue the turbine experiences on start-up, which should help reduce future overhaul costs later in the turbine's life. APS forecasts that the existing HP Turbine outer shell can be refurbished and reused, reducing cost.

In addition to the immediate improvements in fuel efficiency, production output and avoiding a complete turbine failure (which would shut down the unit), there have been strides made in both fabrication materials and machine design which provide further benefits toward reducing long-term turbine maintenance. Because these long-term maintenance reductions are dependent on service conditions over time and other factors, SCE cannot fully quantify this benefit. However, industry experience has demonstrated that long-term O&M cost savings are possible and will likely result in decreased maintenance costs during subsequent year major overhauls (with the first of these major overhauls being six years after the turbine is replaced).

This expenditure will also replace turbine controls system field devices and mechanical linkages which currently measure the position of the control valves, steam temperatures, and pressures, resulting in efficiency and reliability. The controls system components currently being utilized are old (1960's design) and have reached the end of their useful lives. Maintaining these systems to a high level of reliability has proven to be difficult and labor intensive. Start-ups have been negatively affected by erroneous indications of these field devices, resulting in start-up delays and unit trips. Replacement of these devices will improve future start-up performance.

This expenditure will be implemented with other major capital projects to be performed during the planned 2008 Unit 5 Major Overhaul. The Benefit to Cost Ratio for this expenditure is 4.3.

2. High Pressure Turbine Replacement and Controls Upgrade Unit 4

This $16.231 million project expenditure (of which SCE's share is $7.791 million) addresses the same need described in the above project for Unit 5. This work will be performed during the next planned major overhaul for Unit 4, currently scheduled for 2010. The difference in cost between this project, and the nearly identical project on Unit 5, is due to two years of forecast escalation of the turbine steam path purchase prices, and installation cost.

Like Unit 5, during the most recent Unit 4 overhaul completed in 2002, the Unit 4 HP lower inner shell was found to be exhibiting cracks. The cracks were repaired at that time and the unit returned to service. However, the need for such major weld repairs will rapidly increase in scope and frequency if the turbine components are not replaced. As with the identical project on Unit 5, the inner shells will be replaced. Replacement of this equipment will be required in the relatively near future if the plant is to continue to operate. The Benefit to Cost ratio for this expenditure is 3.8.

3. **Minor Overhaul Turbine Repairs Unit 5**

This $6.534 million expenditure (of which SCE's share is $3.136 million) provides for the Unit 5 turbine minor overhaul currently planned for 2011. Based on recent turbine inspections, we forecast that capital expenditures will be incurred during the minor overhaul, primarily for LP turbine blade replacements of the 4th row A rotor. This area recently failed on the other three LP rotors at Four Corners, and based on the preliminary analysis of those failures, we believe that Unit 5 A rotor blades are nearing the end of their service life. Alternatives such as running the turbine without the blades would still require a large expenditure to implement, and would result in decreased output. Blade replacement, as we forecast here, is the most economical alternative. The Benefit to Cost Ratio for this project is 4.9.

4. **HP Generator Field Rewind Unit 4**

This $2.185 million capital expenditure (of which SCE's share is $1.049 million) provides for the Unit 4 High Pressure Generator Field (Rotor) to be refurbished by re-winding the internal rotor coils utilized to carry excitation (DC) currents to the generator field. The Unit 4 HP Generator Field has been in service over 30 years and the windings have reached the end of their useful life. The generator will be rewound during the 2010 overhaul. The 2004 overhaul visual examinations, electrical and mechanical testing, and recent on-line Flux Probe monitoring have revealed an increase in faulted turns. Turns are defined as the areas at both ends of the rotor where the coils loop back to the opposite end of the rotor. Centrifugal and thermal forces act on the copper buss sections embedded in the insulating materials separating the conductors from the rotor body. As the rotor turns at an RPM of 3600, the cylindrical rotor experiences thermal and centrifugal forces resulting in 'growth' (i.e.

elongating of the windings while in operation due to thermal effects of the conductors carrying DC current throughout the windings). This elongation over a long period of time results in abrasion of the insulating materials separating the ground wall from the conductors and causes a 'short' in the field winding. This damage is typically most severe at the winding turns. The field can be operated with a few faulted turns as long as they are in the same polarity sections of the field. However, if the number of faulted turns increases above the acceptable and safe operating level, or spreads to other polarity sections, the generator must be taken out of service.

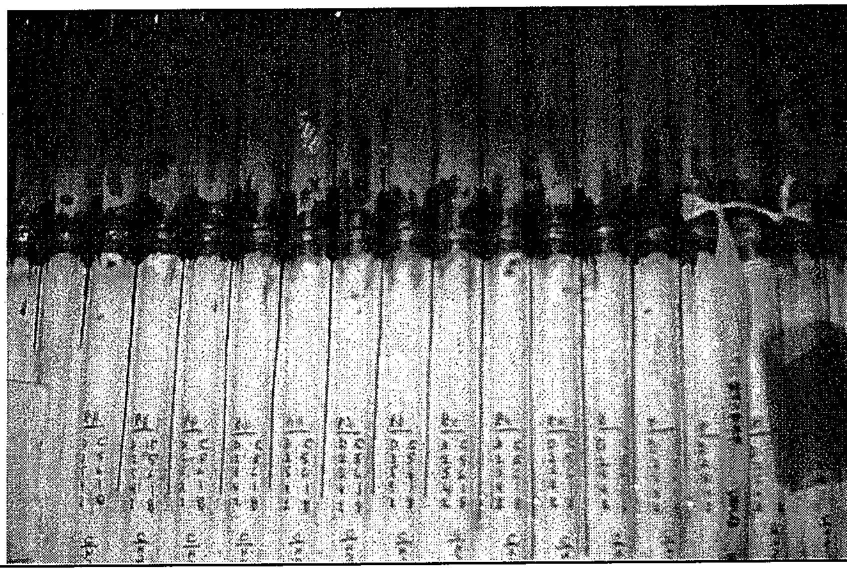
The generator windings are continuing to degrade and the number of shorted turns is increasing. At the forecast rate of further degradation, the generator must be rewound during its next overhaul in 2010, or there is a high probability it will fail in the years immediately following the overhaul. This expenditure is required to maintain electrical power generation output from this generator. The Benefit to Cost ratio for this project is 5.9.

5. <u>Lower Boiler Replacement Unit 5</u>

This $18.495 million expenditure (of which SCE's share is $8.878 million) replaces extensive portions of the Unit 5 boiler waterwall circuitry. This work is being undertaken because tube wall-thinning or wastage has occurred during many years of service in the low NOx burner environment. The waterwall tubes serve as the front, side, and rear walls of the boiler furnace, where the coal is combusted. The scope of work is similar to that performed on Unit 4 in 2004.

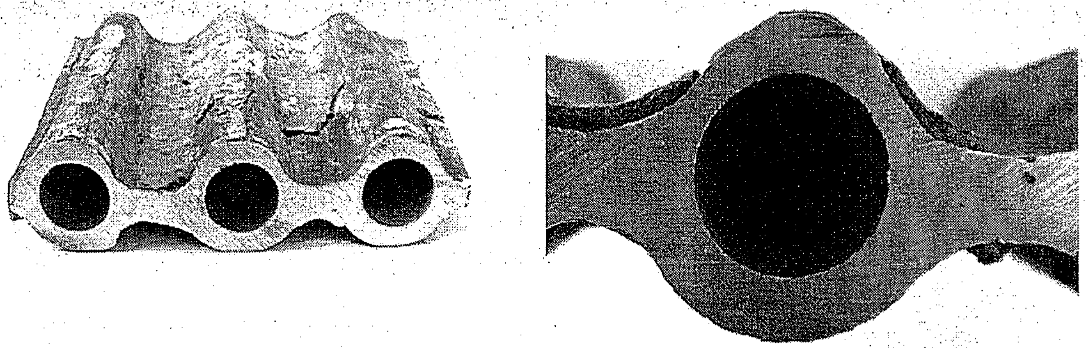
The boiler walls are made up of high-strength tubes, situated side-by-side and connected together in such a manner that hot gases inside the furnace do not migrate to the outside environment. By connecting hundreds of tubes together in this fashion, a large flat surface, or "waterwall" is created (Figure XII-1). These "waterwall" tubes form the front, back, roof, and sidewalls of the furnace. In normal service, water flows inside the waterwall tubes and fires of the furnace transmit heat to the water through the furnace tube walls.

Figure XII-1
Waterwall Tube Panel Welds



The furnace waterwall replacements at Four Corners Generating Station Unit 5 are required due to a waterwall tube damage wastage mechanism known in the industry as "waterwall fireside corrosion." See Figure XII-2 for a waterwall tube fireside corrosion sample taken from Unit 5.

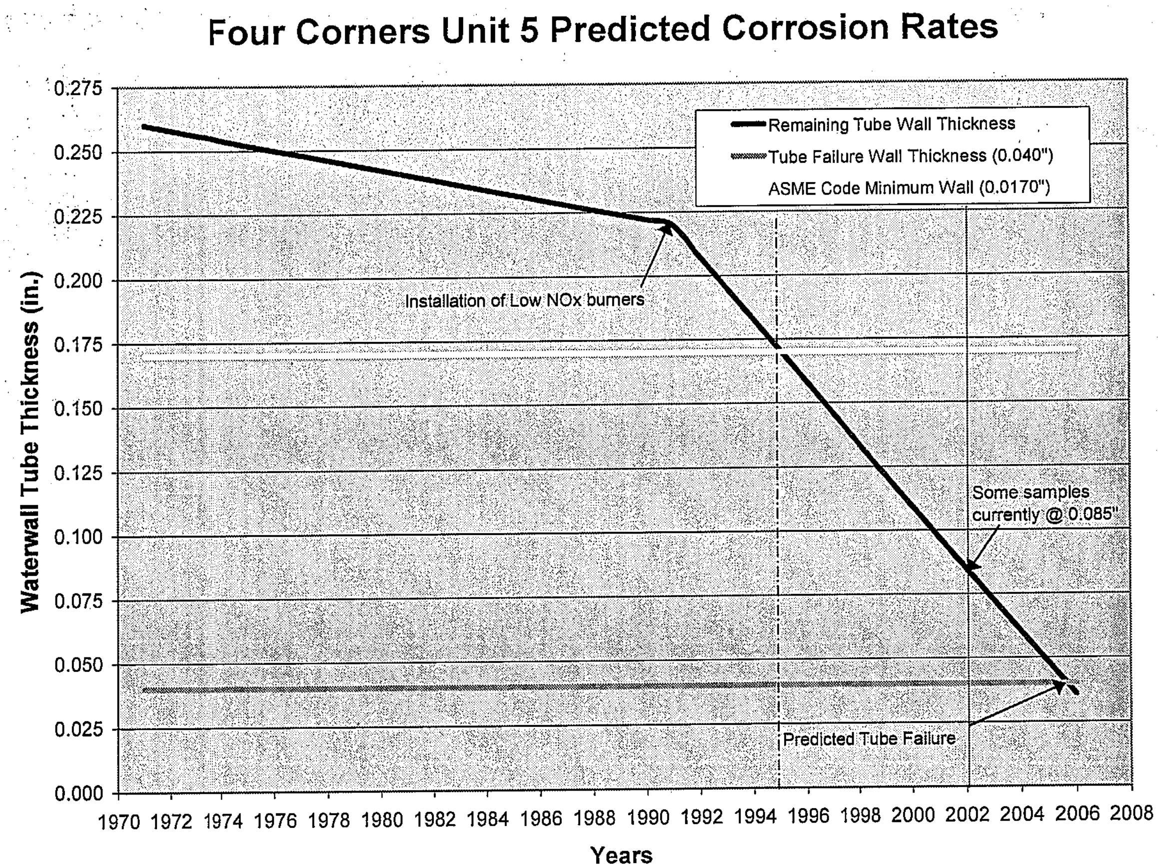
Figure XII-2
Waterwall Fireside Corrosion



Waterwall fireside corrosion damage is the result of combustion products being deposited on the tubing fireside outside diameter. These corrosive compounds attack the tube surfaces and aggressively reduce tube wall thickness. Fireside corrosion associated with an oxygen reducing atmosphere was magnified by the installation of low NOx burners in the 1989 to reduce the plant's level of air pollution emissions. This phenomenon is typical of boilers with low NOx burners. That is, these burners affect the chemistry of the combustion process in a manner which leads to an increase in boiler tube external corrosion.

APS performed tube wall thickness examinations on Unit 5 during its last major overhaul in 2002. These measurements revealed that tube wastage is widespread. Tube wall thickness was reduced from original wall thickness of 0.260 inches to under 0.085 inches in the worst areas. Many waterwall tube areas inspected experienced 40 percent to 60 percent loss of original wall thickness. Failure is predicted when tube wall thickness is reduced to approximately 0.40 inches but can occur even sooner in certain circumstances. Records indicate that the rate of tube wall thinning was greatly accelerated after the installation of low NOx burners. A graph showing the approximate rate of thinning over the life of the unit is shown in Figure XII-3.

Figure XII-3
Four Corners Predicted Corrosion Rates

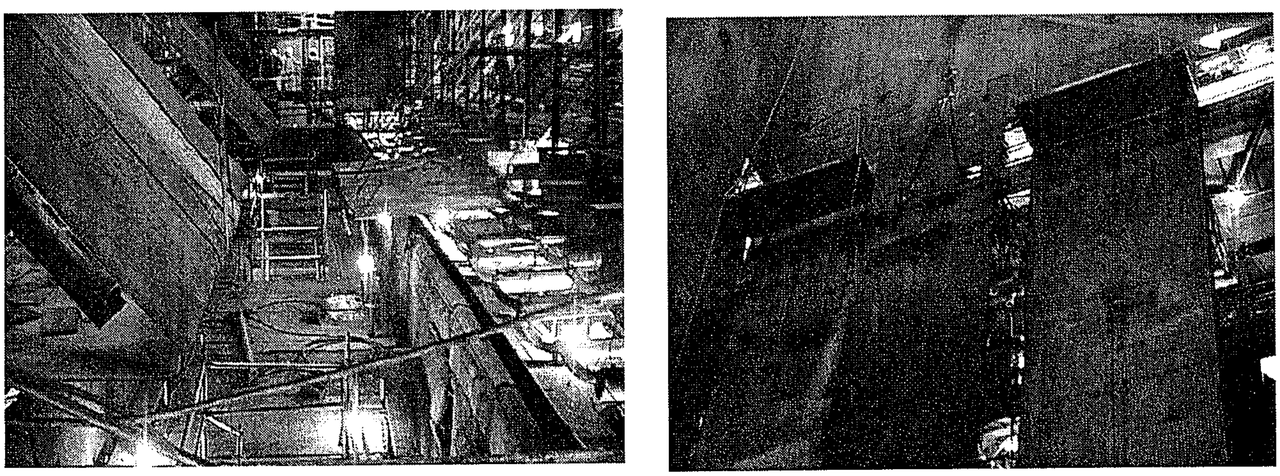


Fireside corrosion was found on the side walls and on the front and rear lower throat (V-bottom) areas of the furnace. APS has performed partial waterwall panel replacements and weld overlay build-up work in an effort to keep the problem from causing substantial immediate forced outages. Weld overlaying of waterwall tubing is intended to be a short-term repair until scheduled replacement can be accomplished during a planned outage. The degree of wastage has now progressed to a point where complete replacement is required to prevent mass area failure and associated tube leaks that would keep the unit down for frequent and significant periods of time. Should the tube wall thickness over a significant area reach the failure point, the high rate of tube leaks could make it difficult to keep the unit on line for any length of time. Replacement of the entire affected areas on Unit 5 is needed to prevent this potential magnitude of tube failures.

In addition to waterwall fireside corrosion, the Unit 5 lower boiler has experienced tube failures due to internal corrosion fatigue, flash erosion, and soot blower erosion. This project will also replace many of the tubes which have damage from these factors. Proceeding with this project is needed to sustain Unit 5 reliability performance.

APS plans to proceed with this work during the 2008 Unit 5 Overhaul. SCE believes the work is necessary to assure reliability of Four Corners. The scope of work will include replacement of the bottom slope (V-bottom), including all four walls, extending up to the 42 foot elevation on the front and rear walls. This will include the first and second pass inlet headers. A seal through skirt and refractory cooling system will also be installed to minimize cooling water header and refractory repair costs during future overhauls. Waterwall coating is also included and will help protect the new panels and prolong waterwall tube life.

Figure XII-4
Mohave photo comparable to Four Corners Unit 4 Lower Boiler Replacement
(Similar Work To Be Performed On Unit 5)



Our economic evaluation includes a conservative assumption of four waterwall fireside corrosion leaks per year requiring an outage long enough to replace a small panel section. This work is planned to begin in 2007 with purchasing of materials, and will be completed in 2008 during the Unit 5 Major Overhaul. The Benefit to Cost Ratio of this project is 4.1.

6. Pendant Reheater And Outlet Header Replacement Unit 5

This $14.581 million expenditure (of which SCE's share is $6.999 million) replaces the Unit 5 pendant reheater tube assemblies and the associated inlet and outlet steam headers. This project will be done during the 2008 overhaul. The reheater is an assembly of tube bundles within the boiler setting that transfers thermal energy from hot combustion gasses exiting the furnace to steam coming from the outlet of the HP turbine. The steam enters the reheater at a temperature between 600 and 700 degrees and exits at approximately 1,000 degrees. The steam is then introduced into the intermediate pressure turbine (IP Turbine) for expansion and release of its energy in the production of electrical power. The existing pendant reheater is the final component of the entire reheat steam system for the Four Corners boiler design, and therefore, has the highest operating temperature of the reheat system.

The Unit 5 pendant reheater has been in service for well more than 30 years. At this length of service, a boiler pressure part in a base loaded power plant is generally considered to be nearing its service life. Recent operating and inspection history indicates the end of the reliable life of this reheater is approaching. These indicators include: an increasing rate of tube failures from various causes related to the service environment; swelling of the headers caused by thermal cycling over time and the extreme operating temperatures; and the development of cracking in and around the tube to header connections.

The degrading integrity of the reheater steam headers introduces a safety concern because an in-service failure of one of the large headers will likely result in substantial collateral damage to adjacent equipment and structural components. This work requires a unit planned outage of at least eight weeks duration.

This expenditure began in early 2007 with purchasing of materials. Fabrication is scheduled to begin around mid-June 2007. This project yields a Benefit to Cost Ratio of 2.8.

7. **Pendant Reheater And Outlet Header Replacement Unit 4**

This $18.981 million expenditure (of which SCE's share is $9.111 million) replaces the Unit 4 pendant reheater tube assemblies and the associated inlet and outlet steam headers. This project is essentially identical to the project discussed above on Unit 5, and is required for the reasons noted above on Unit 5. This work will be performed during the next planned major overhaul for Unit 4, currently scheduled for 2010.

The increase in cost between this project and the identical project on Unit 5 reflects major increases in the price of boiler steel since the Unit 5 components were ordered. There are only three foundries currently in operation that can produce the large diameter seamless pipe used to fabricate the specialized Outlet Headers. The pipe and header materials have a procurement lead time of twenty months. The Unit 5 tube and header assemblies have already been ordered and arrived in the United States. The Unit 4 material for essentially the same project is planned for procurement in July 2007. Recently obtained preliminary vendor pricing indicates the materials for this Unit 4 project will cost 30 percent more than the same project on Unit 5. Nevertheless, it is necessary to proceed with this project in order to sustain Unit 4 reliability performance into the future.

The Benefit to Cost Ratio for this expenditure is 2.1.

8. **Second Stage Pendant Superheater Replacement Unit 5**

This $11.187 million expenditure (of which SCE's share is $5.370 million) replaces the Unit 5 boiler pendant superheater tubes that have become unreliable and are subject to in-service failures that result in lengthy forced unit outages. This project will be done during the 2008 Unit 5 major overhaul.

The secondary superheater is located downstream from the primary superheater and performs the final heating of the high pressure steam before it is routed to the high pressure steam turbine. This section of boiler tubes operates at the highest temperature of the various superheater boiler tube assemblies.

The secondary superheater has a first stage and a second stage; that is, it consists of two sets of assembly tube bundles. The secondary superheater bundles are called "pendants" due to their geometry. The secondary superheater assembly tube bundles are within the boiler setting that transfers thermal energy from the furnace radiant heat and the hot combustion gases. The steam enters the secondary superheater after flowing through the primary superheater section of the large boiler. Main steam exiting the secondary superheater is introduced into the high pressure turbines for expansion and the release of its energy in the production of electrical power.

The existing secondary superheater tubes have been in service since 1981. Their primary failure mechanism is long-term overheating, also known in the industry as a "creep failure" mechanism. This failure mechanism results from a gradual weakening of the steel over many years of service at very high temperatures. It is common for high temperature final superheater tubes to incur creep damage under normal operating conditions after many years of service. Superheater boiler tubes have a finite creep life and creep damage is cumulative and is a function of temperature and years of service. Creep damage can be detected in several ways including by taking measurements of the tube diameter. Tubes having creep damage will be deformed (i.e. swollen larger than their original size, and often no longer round as when they were fabricated). Creep damage is also associated with a build up of internal tube wall scale over many years of operation that acts like a layer of thermal insulation. This internal insulation causes the outer tube surface to run hotter, which further weakens and deforms the steel. The second stage secondary superheater tube failures have exhibited this inside diameter insulating scale.

The secondary failure mechanism of concern is Dissimilar Metal Welds (DMW). Analysis of the condition of these welds indicates we will soon begin experiencing tube failures and unit outages at these weld locations. These welds were part of the original construction of the boilers. The welding procedures used in industry at the time of initial construction have now been determined to be less than optimum by today's standards.[10] Replacement of this section of the boiler, with new tube pendants fabricated using modern weld techniques to join dissimilar metals, will eliminate the DMW problem areas present in the existing pendants.

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[10] Dissimilar Metal Welds are required in high temperature sections of boiler reheater and superheater tubing to join low allow steel tubing to stainless steel tubing. Over time the difference in the coefficients of expansion cause high stresses to develop at the relatively weak weld interfaces.

Tube samples, non-destructive examination, oxide scale measurements and Electrical Power Research Institute computer based modeling known as (PODIS)[11] have confirmed the tubes are nearing the end of their life. Replacement of secondary superheater tubes is required to maintain boiler reliability. Frequency of boiler tube leaks and associated generation losses are projected to increase if this equipment is not replaced during the 2008 Major Overhaul. This project yields a Benefit to Cost Ratio of 6.0.

9. **First Stage Pendant Superheater Replacement Unit 5**

This $13.320 million expenditure (of which SCE's share is $6.394 million) replaces the Unit 5 Second Stage boiler pendant superheater tubes that have become unreliable and are subject to in-service failures that result in lengthy forced unit outages. This project is very similar to the above project, which entails the replacement of the second stage of the Unit 5 secondary pendant superheater. However, this project is for replacement of the FIRST stage of the secondary superheater on Unit 5.

The existing Unit 5 secondary superheater first stage tubes are mostly original equipment and have been in service since 1970, with several smaller sections having been previously replaced during minor outages. Several tube failures have occurred in the first stage tubes over the past four years, for essentially the same reasons that are causing problems with the second stage tubes. Non-destructive examination, tube samples, and oxide scale measurements have confirmed the tubes are reaching the end of their service life. Additionally, APS has conducted modeling using the EPRI computer based software tool known as PODIS which has confirmed the tubes are nearing the end of their service life.

Replacement of secondary superheater tubes is required to maintain boiler reliability. Frequency of boiler tube leaks and associated generation losses are expected to increase if this equipment is not replaced. This work can only be performed with the unit out of service for many weeks. We currently forecast this project will be conducted during the Unit 5 2011 minor overhaul.

[11] Electrical Power Research Institute computer based modeling software for Dissimilar Metal Welds (DMW) known as P.O.D.I.S. (Prediction Of Damage In Service) performs a probabilistic analysis of the lifetime of dissimilar metal welds in superheater/reheater tubes. The presence of dissimilar welds is one of the factors that influence service life. The PODIS model also takes into account creep and fatigue damage to predict boiler tube service life.

This project yields a Benefit to Cost Ratio for this project of 3.6.

10. Second Stage Pendant Superheater Replacement Unit 4

This $14.081 million expenditure (of which SCE's share is $6.759 million) is essentially identical to the project discussed above on Unit 5, and is required for the reasons noted above on Unit 5. This work will be performed during the next planned major overhaul for Unit 4, currently scheduled for 2010. The increase in cost between this project and the identical project on Unit 5 is due to a large increase in the price of boiler steel since the materials were ordered for the near-identical Unit 5 project in July 2007. Preliminary vendor pricing is the basis for the forecast increase in this Unit 4 project compared to the same project on Unit 5.

The Benefit to Cost Ratio for this project is 3.5.

11. Horizontal Reheat Bank Replacement Unit 5

This $6.310 million expenditure (of which SCE's share is $3.029 million) replaces the Unit 5 Horizontal Reheat Bank boiler tubes which have been in service since 1970. Over many years of service the Horizontal Reheat tubing has experienced long term over-heat, heat cycling, fly ash and soot blower erosion which results in boiler tubing wall thickness reduction. If not replaced, continued degradation of the Horizontal Reheater will result in an increasing rate of tube failures, and plant outages. The horizontal reheat banks were replaced on Unit 4 in January, 1996. The identical project now needs to be performed on both Unit 5 reheater banks in order to sustain plant reliability.

This will be completed during the Unit 5 major overhaul in 2008. The project began in 2007 with purchase of materials as required to secure firm delivery dates necessary to meet the outage timing. The Benefit to Cost Ratio project is 9.2.

12. Boiler Nose Replacement Unit 4

This $4.000 million dollar expenditure (of which SCE's share is $1.920 million) will replace Unit 4 Boiler waterwall tube panels that make up the Boiler Nose. This project will be completed during the Unit 4 Major overhaul in 2010.

Replacement of this area of boiler tubing is required in order to reduce tube leaks resulting from corrosion fatigue. If not replaced, this area will experience an increasing rate of tube leaks resulting in forced outages. The Boiler nose also has severe soot-blower erosion caused by the many years of operation of the adjacent soot blowers. Soot-blowers operate throughout each day to clean boiler tubes of ash deposits. If not cleaned, the ash would build-up on the tubes. This would reduce boiler fuel efficiency and steam output, resulting in a decrease in plant power output. However, the blasting action of the soot-blower upon the ash erodes the tube surface over the years.

This erosion can be temporarily repaired by pad welding over the eroded areas. At least fifty percent of the Nose tubes have been repaired by pad welding. However, pad welding is not considered a reliable and permanent repair. This section of the boiler is quickly reaching the end of its useful life and must be replaced in order to sustain plant reliability performance.

As discussed in previous boiler tubing projects, the cost forecast for this project reflects materials, fabrication, and delivery prior to the 2010 Major Overhaul. This project has a Benefit to Cost Ratio of 2.6.

13. Boiler Nose Replacement Unit 5

This $4.190 million expenditure (of which SCE's share is $2.011 million) replaces Unit 5 Boiler waterwall tube panels that make up the Boiler Nose. This project is essentially identical to the project described above on Unit 4. The difference in cost reflects approximately one year of forecast escalation of material and installation. Replacement of this area of the Unit 5 boiler tubing is required in order to reduce tube leaks resulting from corrosion fatigue and severe soot-blower erosion. The objective of this project is to maintain unit reliability. This project is currently forecast to be performed during the Unit 5 minor overhaul in 2011.

The Benefit to Cost Ratio for this project is 2.4.

14. Main/Igniter Flame Scanner Replacement Unit 5

This $2.379 million expenditure (of which SCE's share is $1.142 million) replaces the Units 5 boiler flame scanners, sections of the cooling air piping, and forced air fans. This work will be done during the Unit 5 2008 overhaul. The flame scanners have become unreliable due to their age and exposure to severe service conditions that includes very high temperatures at the burner front location.

The cooling air and purge air system piping will also be replaced to ensure the new scanners do not overheat and prematurely fail.

Flame scanners are required by National Fire Protection Association (NFPA) code in boiler operations. After ignition is initiated at a burner, the successful establishment of flame at that burner must be verified (proved) by a flame scanner, otherwise, the burner has to be shutdown. The introduction of fuel into a hot furnace, where the flame has gone out, could cause a severe boiler explosion. For safety reasons, flame scanner systems are designed such that, if they fail, they will fail with a "no-flame" indication, thereby preventing the start-up of burners. Under certain conditions, their failure can shutdown an operating burner, often causing a reduction in plant electrical generation.

The combination of the location of the flame scanners at the burners and past incidents of unreliable air flow have caused the existing flame scanners to fail. The flame scanners have been failing frequently causing unit startup delays, and delays in attaining higher load due to not being able to have needed burners in service. The electronic assemblies of the flame scanners are failing randomly, indicating an end-of-life condition for the scanners. To improve the future scanner reliability, it is imperative that the scanner cooling system also be modified and improved along with the scanner replacement.

Unit 5 project costs are forecast to be higher than the similar project discussed below for Unit 4 due to Unit 5 being selected as the test unit for engineering analysis, testing, and selection processes required prior to making decisions as to which vendors equipment would be chosen for purchase and installation. Equipment to be evaluated was temporarily installed, analyzed, evaluated, and measured competitively for performance and durability against other vendor's equipment. Some of the testing modifications (such as piping, flanges, and conduits) can be kept in place when the full installation is performed, which offsets part of the cost of this initial testing.

The replacement flame scanners will incorporate an improved scanner assembly, larger diameter cooling air piping to deliver higher volumes of cooling to the scanners and larger cooling air fans. This work will result in increased reliability and longevity of this critical equipment operating in a very hot boiler environment.

The consequences of scanner failure include delays in unit startup, inability to reach a higher load, unit trips, and in extreme cases an explosion of the boiler furnace. This expenditure is being undertaken primarily for reliability purposes, although the safety benefits are obvious. This expenditure has a Benefit to Cost Ratio of 3.6.

A very similar flame scanner project is scheduled for installation on Unit 4 in 2010 for essentially the same reasons described above for Unit 5. Unit 4 has a lower forecast cost than this same project on Unit 5 for the reasons discussed above. As the Unit 4 project is slightly under $1 million, it is included in our discussion of projects which are forecast to cost less than $1 million.

15. Air Preheater Hot and Cold Basket Replacement Unit 4

This $2.180 million expenditure (of which SCE's share is $1.046 million) replaces the hot and cold side heat transfer elements in the Unit 4 secondary air preheaters (SAPH). This work will be done during the 2010 Unit 4 overhaul. Air preheater elements (baskets) transfer heat from exiting boiler flue gas to incoming secondary air, or combustion air. Each air preheater has layers of elements that provide heat transfer. The first elements to come into contact with hot flue gas are referred to as the "hot end elements." Layers in the middle are referred to as "intermediate elements" and the final layers are referred to as the "cold end elements." The heat transfer elements are fabricated from thin gauge steel sheets that are stacked one on another in small groups, several feet thick. These groups, or baskets, are held together with steel reinforcements. An air preheater at Four Corners will have many of these baskets arranged in a circle.

The thin gauge steel sheets deteriorate over time because of corrosion from flue gas products and from fly ash erosion. When excessively worn, the heat transfer elements must be replaced. If not replaced in a timely manner, pieces of steel become dislodged and may fall into other equipment or damage the air preheater drive mechanisms, resulting in high maintenance costs and creating the potential for forced unit outages. Additionally, as heat transfer elements wear away, the amount of actual heat transfer that takes place is reduced, resulting in degradation to boiler efficiency (i.e., higher coal fuel costs).

The Benefit to Cost Ratio for this project is 1.2.

16. **<u>Coal Piping Replacement Unit 5</u>**

This $4.000 million expenditure (of which SCE's share is $1.920 million) is to be completed in two phases. Phase I replaces only the elbow sections of the coal conveyance piping, and will be done during the Unit 5 major overhaul in 2008. Phase II will be completed at a future date outside this rate making period, and will replace the straight sections of the Unit 5 coal conveyance piping.

This piping connects the coal pulverizers (mills) to the coal burners that inject coal into the furnace. Coal fuel at Four Corners is ground to a fine powder consistency by the coal mills. There are eight mills per Unit of which each mill has six coal pipes for a total of 48 mill discharge pipes per unit. The existing coal pipes require replacement as they are wearing thin from internal abrasion caused by the finely ground coal traveling at high velocities as it exits the pulverizer mill.[12] Any time a pulverizer is removed from service due to a coal piping leak, the Unit load is curtailed an average of 50 MW. In addition to lost generation and rising maintenance costs, the leaking coal dust presents a fire risk, and could cause the station to exceed its fugitive dust emissions limits. Replacement of the Unit 5 coal piping elbows during the 2008 overhaul is needed to sustain Unit 5 reliability performance, and avoid an increase in future maintenance costs for an increasing amount of coal piping repairs.

The Benefit to Cost comparison for this expenditure is 2.5.

17. **<u>Coal Piping Replacements Unit 4</u>**

This $8.867 million expenditure (of which SCE's share is $4.256 million) will replace much of the Coal Piping on Unit 4 during the major overhaul in 2010. The scope of the replacement on Unit 4 is greater than that planned for the Unit 5 project discussed above. This is due to piping inspection findings concluding that straight sections and all elbows of piping will need replacement during the 2010 overhaul to ensure Unit 4 reliability and safety is not compromised. That is, while the Unit 5 piping can be replaced in two phases (as the Unit 5 straight piping runs are not yet severely

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[12] The coal piping has many bends as required to connect the mills to the burners. These bend areas wear through more quickly than straight piping areas. The bends areas have been patched many times. The bends can no longer be effectively repaired, and must be replaced.

eroded), all of the targeted Unit 4 coal piping is forecast to require replacement in a single large phase during the 2010 overhaul.

The benefit to cost for this project is 2.0.

18. High Pressure Feedwater Heater Replacement Unit 4

This $4.000 million expenditure (of which SCE's share is $1.920 million) replaces Unit 4 South 4th Point Feedwater Heater on Unit 4. In 2010, the 4th Point Feedwater Heater will be 26 years old and near the end of its predicted service life.

The purpose of feedwater heaters is to increase the fuel efficiency of the plant by using small portions of the steam extracted from various stages of the turbine to preheat the water entering the boiler. This process reduces the amount of coal fuel required to turn the water into superheated steam, improving the plant's overall fuel economy. Six stages of feedwater heaters are used.

The Unit 4 South 4th Point Feedwater Heater is experiencing recurring tube leaks and will soon reach the point where it must be permanently removed from service if not replaced. Removal from service would negatively impact the plant fuel efficiency (i.e., heat rate and fuel costs).

The benefit to cost for this project is 2.6.

19. Pulverizer Refurbishment and Capacity Upgrade Unit 4

This $4.000 million expenditure (of which SCE's share is $1.920 million) provides for parts and materials required to refurbish and upgrade all eight Unit 4 Pulverizers to a higher capacity throughput. This work will be done during the Unit 4 2010 overhaul. This project will help reduce the amount of load reduction we experience when two or more pulverizers are out of service. The pulverizers reduce the coal particle size to a fine powder before the coal is admitted into the boiler furnace. If particle size is not correct, the unit will experience combustion problems and would have to be shut down due to emissions constraints or other problems.

Due to their inherent design coal pulverizers are a high maintenance item. Pulverizers are frequently out of service for routine maintenance and repairs while the plant is on line. Absent refurbishment, the pulverizers will continue to degrade and will more frequently cause partial load restrictions. Refurbishment is needed to sustain plant reliability. Upgrades during the refurbishment will also be performed to increase each pulverizer's maximum output. This will reduce the unit load restrictions when two or more pulverizers are out for maintenance. Currently, when two pulverizers on a single unit are out of service for either scheduled or unscheduled maintenance, unit load must be reduced by 75 MW to 100 MW, depending on coal BTU quality. After the pulverizer upgrades, unit load will only have to be reduced by 25 MW to 50 MW (i.e., an improvement of 50 MW).

The benefit to cost for this expenditure is 1.7.

20. <u>GSU Transformer T633 And T634 Replacements Unit 5</u>

This $3.837 million expenditure (of which SCE's share is $1.842 million) replaces two of the three main power transformers for Unit 5. This expenditure is required because two of the three main transformers, T633 and T634 are now reaching the end of their useful life. The replacement of T633 and T634 transformers is part of APS's program of methodically monitoring all large power transformers and proactively refurbishing or replacing those transformers that are nearing the end of their service life. The replacements will be done in 2008.

The APS transformer program includes maintaining spare transformers. Several spares must be maintained because the electrical size, ratings, and physical configuration of the many transformers at the station varies. That is, there are several different groups of transformers in use at the station. Many of these spares are actually old units that were previously replaced by newer units, as the old units were at the end of their service life. Sometimes, an in-service transformer will be found to have degraded significantly since its last test. A spare will be installed in its place. However, that spare must then be replaced. If that spare was an old previously-used unit, then the new replacement (once delivered) will be installed, and the previously used unit is then taken back out of service and returned to the "spare" position. Because we have some spare units, APS has some flexibility in how we schedule replacements, and can sometimes send a unit out for rewind rather than replacing it. However, ultimately, when a transformer reaches the end of its life, it must eventually be replaced, even if a spare unit is available to serve as a temporary replacement.

Transformer T633 is one of three GSU (Generator Step Up) transformer groups and T634 is one of three transformer groups that delivers the generator output from Unit 5 to the power transmission grid via the 500 kV Switchyard. The generator step-up transformers were installed during original plant construction in 1968. Based on inspections and tests, APS has determined that these two transformers are at the end of their useful lives and thus require replacement.[13] Analysis concluded that the replacement of T633 and T634 during 2008 is required to continue to operate the plant at current levels of reliability.

The Benefit to Cost Ratio for this project is 16.2

21. <u>GSU Transformer T631 Rewind Unit 4</u>

This $3.186 million expenditure (of which SCE's share is $1.529 million) is similar to the project above as it restores an existing transformer to a like-new reliable spare. The T-631 transformer has reached the end of its life as determined by testing and analysis. In June 2006, this transformer experienced increased gassing levels resulting in an outage. It was removed from service and a spare installed in its place. T-631 now sits as an "emergency use only" spare for Unit 4 until the new replacement transformer arrives and is installed during the 2008 major overhaul. We will then send the T-631 transformer out for rewind.[14] T-631, once rewound, will be placed back in Unit 4 as a reliable spare. The prior spare will be used in the replacement of additional identical Unit 4 transformers in future years.

The benefit to cost ratio for this project is 19.4.

22. <u>GSU Transformer T629 Replacement Unit 4</u>

This $3.933 million dollar expenditure (of which SCE's share is $1.888 million) is similar to the project above. The T629 transformer has reached the end of its life as determined by testing and analysis. In this case, we must order a new replacement for the 2010 overhaul.

The benefit to cost ratio for this project is 16.7.

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[13] During the past transformer oil DGA (Dissolved Gas Analysis) tests on these step up transformers have exhibited upward trends of combustible and entrained gasses which is indicative they are at the end of their service life.

[14] Rewind of a high voltage transformer is a capital expenditure based on our accounting guidelines.

23. **Underground Cable Replacements (Annual)**

This $10.000 million expenditure (of which SCE's share is $4.800 million) is for a multi-year program to replace a portion of the underground cables for Units 4 and 5. These cables targeted for replacement are original equipment (i.e., 37 years old) and are reaching the end of their useful lives. An underground cable failure in 2006 involving the Reserve Auxiliary Transformers cabling resulted in forced outage of both Unit 4 and Unit 5, and a loss of generation for a considerable period of time. The cabling faulted due to degradation of the insulation materials (i.e., "insulating jacket") covering the conductors. The remaining original cables require replacement to avoid incurring similar in service failures in the future.

This program will begin in 2008 and will run through at least 2011, and has a benefit to cost ratio of 2.3.

24. **Plant Perimeter Security Upgrade**

This $4.000 million expenditure (of which SCE's share is $1.390 million) provides for relocation of the security guard shack and plant entrances. Additionally, this project will upgrade all plant entrances with card keys, automatic gates, security cameras and additional lighting. This project also provides for new fencing, security cameras and perimeter lighting in other areas where needed. This work will be done in 2010 commensurate with new power plant security regulations.

One key objective of his project is to move the security boundary further away from the operating units. The project will also provide secure access and monitoring for all parts of the plant in order to comply with North American Electric Reliability Corporation (NERC) physical security standards for a critical asset. These standards were recently established to assure the reliability and safety of the bulk power grid in the United States.

Currently, there are multiple plant entry points that do not meet NERC physical security standards for secure access to the plant. Due to the large area to be covered, the current security measures are inadequate or have no means of monitoring the access points and perimeter fencing. Some areas do not have sufficient lighting to be able to monitor the perimeter during the night. Some critical entrances will need to be equipped with card key readers, security cameras and improved lighting.

Assuming the Four Corners power plant will be declared a critical asset, plant security will need to comply with NERC physical security standards by 2010. While this project is a reliability project (i.e. it reduces the risk that the plant would be shut down due to sabotage), it is also required to comply with regulations and therefore a site-specific economic analysis was not conducted.

25. Computer Predictive/Performance Tools (Annual)

This $3.000 million capital expenditure (of which SCE's share is $1.043 million) provides for installation of the latest measurement and computer based Predictive/Performance tools. The software based tools will interface with the plant's computerized data historian. The purpose of this project is to use the latest Predictive/Performance technology to aide in the evaluation of key processes in order to optimize performance and sustain plant reliability.

This Predictive/Performance technology applies to both operational conditions and determining required predicative maintenance needs through the use of computer generated models, the monitoring of multiple interacting process and the ability to predict the impact if corrective action is not taken. Maintenance and operating parameters can then be adjusted to deliver more optimal results. Projects such as this are needed to sustain reliability at historic performance levels as we face increasing aging of this 37 year old plant.

The basis for the cost estimate reflects manufacturer's data, recent project history and engineering experience. This expenditure provides hardware and software to be utilized for Reliability Centered Maintenance initiatives consisting of plant equipment and performance monitoring, engineering evaluations, and budgeting forecasting.

The benefit to cost ratio for this expenditure is 1.6

26. Bottom Ash Controls Replacement Unit 4 and Unit 5

This $2.267 million expenditure (of which SCE's share is $1.088 million) is to replace the existing Bottom Ash Handling Equipment Control System with current Distributed Control System (DCS) technology in order to ensure a safe and environmentally compliant facility waste processing operations, and to maintain plant reliability. The existing Bottom Ash Control System has a long history of problems and has deteriorated. Plant operations can no longer depend on the system. The existing system is unreliable and is not used in an automatic mode. Bottom Ash has to be removed from the furnace every three hours or the molten ash starts building up and bridging. This can cause the need to incur a forced outage to remove the unit from service, to manually clean the ash and slag from the furnace.

By controlling the Bottom Ash system with a modern control system, problems associated with timer and relay miss-operations will be eliminated. The inherent capability of the DCS also enables the problems with field devices to be readily identified and fixed. The new system will also allow the control operator to be able to start an "ash pulling sequence" automatically, and to monitor the status of the system including the control and status of the seal trough level.

This work will be complete in 2009. The benefit to cost ratio for this project is 1.7.

27. Future Reliability Projects Unallocated

This $37,768 million (of which SCE's share is $18.129 million) expenditure provides funding for future projects for which specific funding has not yet been allocated. Based on our many years of experience operating power plants, we forecast that between now and the end of 2011 additional capital needs will arise which have not yet been accounted for in our current capital forecast.

As described earlier, SCE has developed a five year forecast of capital expenditure requirements for coal-fired generating stations for this filing. We discuss the methods used to develop our forecast in Chapter XI section A. We also explained in Chapter XI section D that the level of certainty contained in our forecast decreases as projections are made further into the future. This is especially true in view of the age of Four Corners, and the uncertainties regarding future regulatory changes that can impact coal-fired generating stations.

APS, as Operating Agent, has identified many of these required future capital expenditures. However, our operating experience is that we cannot define all requirements of a 37-year old coal-fired generating station three or four years in advance. Plant performance changes with time, equipment problems reveal themselves with time and equipment needs shift with time. Based on our prior experience, these future projects will mostly be related to our need to sustain our reliability performance. However, this could also include new projects needed to address future regulatory changes. Usually, the regulatory change process is long enough that we have sufficient advance knowledge to include funding for such project needs in our forecast. However, this is not always to case.

Therefore, SCE cannot definitively state all capital expenditures that will be required to support the operation of Four Corners Generating Station in 2007 through 2011. This is especially true because APS will perform a major overhaul of Unit 5 in 2008 and a major overhaul on Unit 4 in 2010. Inspections conducted during the overhauls may reveal the need to immediately proceed with replacement of certain equipment components as part of the overhaul. Our overhaul planning takes into account prior inspections and conditions observed during operations. However, these observations do not always give us forewarning of damage we might find during the overhaul inspections. Many of these unforeseen overhaul repairs could qualify as capital expenditures under our accounting guidelines.

During 2007 through 2011 we could also incur the need to immediately conduct capital expenditure for major repairs that are not associated with the overhauls. For instance, we just recently discovered severe cracking in the LP turbine on Unit 4 and Unit 5. This caused a forced outage on Unit 5 in 2007, and required extending the 2007 planned outage on Unit 4 to correct these problems. The needed repairs consisted of modifying the turbine rotor so that re-designed 4th row rotating turbine blades could be installed (i.e., the existing blades had to be replaced with a re-designed set of blades to correct the problem). Replacement of turbine blades is a capital expenditure, in accordance with accounting guidelines. Therefore, a capital expenditure of approximately $6.8 million was incurred to make these repairs, of which SCE's share was approximately $3.4 million.[15]

This capital expenditure for LP Turbine 4th Row Blade Replacement was not included as a specific line item in our current capital forecast, nor was it included in any of our prior capital forecasts for Four Corners. Therefore, funding for it must be covered in the "Future Projects, Unallocated" line item in our capital forecast. Based on our past experience, we expect to incur similar unforeseen capital projects between now and the end of 2011. Therefore, our capital expenditure

[15] The repair to Unit 4 was not yet complete at the time of this writing; therefore, the above figures are preliminary. The final repair cost could end up being higher, and is very unlikely to be appreciably lower.

forecast for Four Corners includes a $18,129 million (SCE Share) for unallocated expenditures, which accounts for 10 percent of our total capital forecast. The review, justification and authorization process described in Chapter XI will be used to examine and approve any individual expenditure that are ultimately undertaken at Four Corners as part of this contingency.

28. Reliability Projects less than $1 Million Each (SCE Share)

Table XII-4 lists those Reliability Projects which are forecast to cost less than $1.0 million each. As shown, these projects total $53.415 million ($19.036 million SCE share). These projects thereby represent approximately 14 percent of our $132.645 million (SCE share) total forecast for Reliability projects for 2007-2011.

Table XII-4
Reliability Projects Less than $1 Million Each
($1,000 Nominal)

RELIABILITY PROJECTS < $1 MILLION ($1,000 - Nominal)	In Service	100% Total	SCE Share Fraction	SCE Share $1,000
OVERHAUL				
28- 1 AIR PREHEATER H/C BASKET REPL, U 5	2008	2,000	0.4800	960
28- 2 GEN PROT RELAY REPLACEMENT, U 5	2008	249	0.4800	120
28- 3 IP TURBINE BLADE REPLACEMENT, U 5	2008	1,200	0.4800	576
28- 4 LP GENERATOR FIELD REWIND, U 5	2008	1,828	0.4800	877
28- 5 REHEAT ISOLATION VALVES, U 5	2008	225	0.4800	108
28- 6 SUPERHEAT ATTEMPERATOR REPL, U 5	2008	185	0.4800	89
28- 7 FD FAN MOTOR REPL, U 4	2010	200	0.4800	96
28- 8 GEN PROT RELAY ADDITION, U 4	2010	267	0.4800	128
28- 9 IP TURBINE BLADE REPL, U 4	2010	200	0.4800	96
28- 10 LP GENERATOR REWEDGE, U 4	2010	235	0.4800	113
28- 11 LP TURBINE BLADE REPL, U 4	2010	435	0.4800	209
28- 12 REHEAT ISOLATION VALVES, U 4	2010	225	0.4800	108
28- 13 SBAC MOTOR REPL, U 4	2010	275	0.4800	132
SUB-TOTAL		7,524		3,611
TURBINE GENERATOR				
28- 14 AUX TURBINE OIL FILTRATION SYS, U 4&5	2007	220	0.4800	106
28- 15 HYDROGEN GENERATOR INSTALLATION, U 4&5	2007	385	0.4800	185
28- 16 MAIN TURBINE OIL FILTRATION SYSTEM, U 4	2007	120	0.4800	58
28- 17 REDUND STATOR WATER FLOW MONITOR, U 4&5	2007	180	0.4800	86
SUB-TOTAL		905		434
COAL FUEL SYSTEM				
28- 18 COAL SAMPLER CONTROLS REPL, U4&5	2011	1,000	0.3476	348
28- 19 COAL HANDLING CONTROLS REPL, U 4&5	2011	1,500	0.4800	720
28- 20 COAL HANDLING REDUND PWR, PHASE II, U 4&5	2011	2,000	0.4800	960
28- 21 COAL HNDLG REDUNDANT POWER SUPPL, U 4&5	2007	488	0.4800	234
SUB-TOTAL		4,988		2,262
INSTRUMENT & CONTROLS				
28- 22 MAIN FLAME SCANNER UPGRADE, U 4	2007	1,498	0.4800	719
28- 23 DCS ANALOG MASTER MODULE REPL, U 4	2010	2,000	0.4800	960
28- 24 DCS FIRMWARE UPGRADE	annual	989	0.3476	344
28- 25 DCS POWER SUPPLY REPL, U 4	2010	1,000	0.4800	480
28- 26 FIBER OPTIC CABLE UPGRADE	annual	350	0.3476	122
28- 27 LAN SWITCH UPGRADE	annual	416	0.3476	145
28- 28 AUX STEAM 3110B VALVE REPL, U 4	2007	285	0.4800	137
28- 29 AUX STEAM 3110B VALVE REPL, U 5	2008	300	0.4800	144
28- 30 4KV SWITCHGEAR PROT RELAY REPL, U 4	2010	373	0.4800	179
SUB-TOTAL		7,211		3,229

Table XII-4 (Cont'd)
Reliability Projects Less than $1 Million Each
($1,000 Nominal)

RELIABILITY PROJECTS < $1 MILLION ($1,000 - Nominal)	In Service	100% Total	Fraction	SCE Share $1,000
SWITCHYARD & TRANSFORMERS				
28- 31 ATB BREAKER REPL, 345KV SWYD (ALLOC 5)	2007	2,335	0.1200	280
28- 32 ATB BREAKER REPL, PHASE II, 345KV SWYD	2008	2,100	0.1200	252
28- 33 FC1222 230 KV BREAKER, SWYD (ALLOC 7)	2007	255	0.4800	122
28- 34 FC556 & 652 500 KV BREAKER, SWYD (ALLOC 4)	2008	1,200	0.3200	384
28- 35 SWITCHYARD RELIABILITY UPGRADE, U 4&5	annual	1,500	0.4800	720
28- 36 SWITCHYARD UPGRADES DUE TO BHP	2009	1,800	0.3476	626
28- 37 CONSTR TRANSFORMER SUBSTA REBUILD	2009	628	0.3476	218
28- 38 RESERVE TRANSF BREAKER ADDITION, U 4&5	2007	367	0.4800	176
28- 39 #4 XFMR T541 REPL, SWYD	2009	5,000	0.0346	173
28- 40 345/500 KV XFMR BUSHING REPL	2007	1,325	0.4800	636
28- 41 345/230 KV XFMR BUSHING REPL, 230/345	2009	600	0.0346	21
28- 42 AUX TRANSFORMER SPARE, U 4&5	2009	850	0.4800	408
28- 45 RIVER STATION XFMR BUSHING REPL	2008	50	0.3476	17
28- 46 TYPE U XFMR BUSHING REPL, U 4&5	2008	700	0.4800	336
SUB-TOTAL		18,710		4,370
TOOLS, VEHICLES AND FACILITIES				
28- 47 VEHICLE 2006 4C, 1/2 TON PICK-UP	2007	8	0.3476	3
28- 48 NEW & REPL TOOLS, 2007	2007	150	0.3476	52
28- 49 NEW & REPL TOOLS, AFTER 2007	annual	600	0.3476	209
28- 50 OPERAT HANDHELD READER TOOL SYS	2008	405	0.3476	141
28- 51 VEHICLE REPL, 2007	2007	204	0.3476	71
28- 52 VEHICLE REPL, AFTER 2007	annual	1,000	0.3476	348
28- 53 AIR COMPRESSOR VSI, U 4&5	2007	461	0.4800	221
28- 54 PBX UPGRADE	2007	100	0.3476	35
28- 55 WAN UPGRADE	2008	989	0.3476	344
28- 56 MICROWAVE/PHONE SYSTEM UPGRADE	2009	1,000	0.3476	348
28- 57 TRAINING FACILITY	2007	684	0.3476	238
28- 58 U4&5 MAINTENANCE BUILDING UPGRADE	2011	2,000	0.3476	695
SUB-TOTAL		7,600		2,703
DATA COLLECTION & ANALYSIS, AND MISCELLANEOUS				
28- 59 MISC CAP, ENGR ELECTRONIC FILING COMMON	2007	25	0.3476	9
28- 60 BOILER MAINT TRACKING SOFTWARE, U 4&5	2008	353	0.4800	169
28- 61 DATA HISTORIAN REPL	2007	347	0.3476	121
28- 62 ELECTRONIC DOCUMENTATION UPGRADE	annual	1,950	0.3476	678
28- 63 MAXIMO SOFTWARE UPGRADE	2007	511	0.3476	178
28- 64 PERFORMANCE MONITORING SYSTEM	2008	911	0.3476	316
28- 65 PLANT RTU REPLACEMENT, U 4&5	2007	80	0.4800	38
28- 66 SMARTSIGNAL PRED COND MONITOR	2007	1,180	0.3476	410
28- 67 STATOR LEAK MONITORING SYS, U 4&5	2007	220	0.4800	106
28- 68 MISC CAP EXPEND, 2007 COMMON	2007	230	0.3476	80
28- 69 B INDUCED DRAFT FAN VSI REPL, U 4&5	2007	171	0.4800	82
28- 70 SPARE CIRC WATER PUMP MOTOR, U 4&5	2009	500	0.4800	240
SUB-TOTAL		6,478		2,427
TOTAL RELIABILITY PROJECTS < $1 MILLION		53,415		19,036

These smaller Reliability projects address needs in seven areas of the plant. Each of these areas is discussed below. More information on each of the individual projects is provided in our work papers.

The first area of interest is projects associated with the upcoming 2008 and 2010 overhauls. These include replacing a small but significant portion of the turbine blades, rewinds of generators, replacement of a portion of the air preheater baskets, and other overhaul capital expenditures. All of these projects are needed to assure reliable operation of the units for the six years following the overhauls (i.e., as discussed earlier, major overhauls are generally scheduled every six years at Four Corners).

The next area of interest are projects for the turbine generators that are not associated with the overhauls. These projects will upgrade the turbine oil filtration system, and the generator cooling system. The generator cooling system consists of a hydrogen gas system (the generators are filled with hydrogen gas) and a cooling water system. These projects are needed to address problems which have caused forced outages in the past or are likely to cause forced outages in the future.

The next area of interest are projects for our coal fuel system. The present equipment which monitors and controls our coal fuel system is unreliable and needs replacement. This includes upgrading the power supply for these coal system controls. The present power supply lacks redundancy, and when problems occur the fuel system must be shut down to address them. Adding a redundant (i.e., back-up) power supply will correct this situation.

The next area of interest are projects to upgrade other control systems in the plant. These include replacement of our boiler flame scanners on Unit 4. Flame scanners are a protective device which shuts off the coal fuel should the fire in the furnace go out. Admitting fuel to a hot furnace, where the flame has gone out, can lead to a dangerous boiler explosion. The present scanners can cause false indications of loss of fire, leading to needless boiler trips. The other projects in this area address other control system improvements which we need to perform to assure reliable operation in the future.

The next area of interest are projects associated with the station's switchyard and transformers. These projects include the continued systematic replacement of circuit breakers and transformers which have reached the end of their service life. Transformer condition is regularly monitored, which includes periodically conducting a chemical analysis of the transformer oil. Transformers are scheduled for replacement when this monitoring reveals the transformer is showing symptoms of possibly having an in-service failure in the foreseeable future. In-service failures of high voltage transformers almost always cause a forced outage, and can cause a fire which can damage adjacent equipment or jeopardize employee safety.

The next area of interest are capital expenditures for tools, vehicles, and similar support infrastructure. These needs are a routine part of all power plant capital forecasts, and our forecast is consistent with our past costs for these needs. This area also includes upgrade of the Four Corners training facility and maintenance building. The training facility upgrade supports the increased level of staffing we project will be needed, as discussed in Part I of this volume. The upgrade of the maintenance facility reflects anticipated continued degradation of the current facilities such that upgrade in the foreseeable future will be required.

The next area of interest are projects which upgrade our ability to monitor and analyze the condition of the plant's aging equipment. As previously discussed, Four Corners recently experienced previously unforeseen problems on the LP turbines. When these kinds of events occur, it is very important to get to the root cause of the problem so that it can be corrected. An improper diagnosis of the event can lead to a repair strategy which does not correct the root cause of the problem. This then leads to the risk of the equipment failure recurring in the future. Investigating such failures requires the ability to access and analyze operating data, maintenance history, and similar information, in making the diagnosis. We must upgrade our ability to monitor, store and retrieve this kind of data to assure a higher level of success in our ability to foresee equipment problems, and to diagnose equipment problems which occur.

C. Environmental Projects

Table XII-5 below lists projects we will put into service during 2007 through 2011 in order to assure continued compliance with environmental regulations. These regulations include the issuance of a new Federal Air Implementation Plan for Four Corners recently issued by the United States

Environmental Protection Agency. These expenditures total $90.032 million of which SCE's share is $42.477 million.

Table XII-5
Environmental Projects
($1,000 – Nominal)

ENVIRONMENTAL PROJECTS ($1,000 - Nominal)		In Service	100% Total	SCE Share Fraction	SCE Share $1,000
1	OVERFIRE AIR NOX ABATEMENT U5	2009	8,000	0.4800	3,840
2	OVERFIRE AIR NOX ABATEMENT U4	2010	8,240	0.4800	3,955
3	DYNAMIC CLASSIFIER MODIFICATION, U 4	2010	6,420	0.4800	3,082
4	DYNAMIC CLASSIFIER MODIFICATION, U 5	2011	6,613	0.4800	3,174
5	SO2 CONTROLS REPL, U 5	2008	4,939	0.4800	2,371
6	SO2 CONTROLS UPGRADE, U 4	2010	2,333	0.4800	1,120
7	SCRUBBER OUTLET DUCT LINER REPL, U 4	2010	6,367	0.4800	3,056
8	BAGHOUSE DUST SUPPRESSION, U 4&5	2008	2,356	0.4800	1,131
9	BAGHOUSE TURNING VANES REPL, U 5	2008	2,204	0.4800	1,058
10	DRY ASH LAND FILL, U 4&5 PHASE 1	2007	7,554	0.4800	3,626
11	ASH LANDFILL AND HAUL ROAD, U 4&5 PHASE 2	2011	5,000	0.4800	2,400
12	FLY ASH BENEFICIATION AREA IMPROV, U 4&5	2009	2,500	0.4800	1,200
13	THICK UNDERFL TO LINED ASH IMPOUND, U 4-5	2007	3,406	0.4800	1,635
14	5268' LIFT LINED ASH IMPOUNDMENT, U 4-5	2011	3,529	0.4800	1,694
15	WASTE PROCESSING SYSTEM IMPROV, U 4&5	2009	2,500	0.4800	1,200
16	INTAKE STRUCTURE MODIFICATIONS, U 4&5	2008	3,000	0.4800	1,440
17	RIVER STATION 316B REG MODIF	2011	3,000	0.3476	1,043
18	PROJECTS < $1 MILLION EACH	various	12,071	various	5,453
	TOTAL		90,031		42,477

1. <u>Overfire Air NOx Abatement Unit 5</u>

This $8.000 million expenditure (of which SCE's share is $3.840 million) provides for the design, materials procurement, and construction of an Over-Fire Air (OFA) system consisting of the installation of six over-fire air ports on both the front and rear furnace walls. The OFA ports will each be equipped with control dampers for regulation of air flow into the furnace. Ducting will be routed individually from both the front and rear wall wind-boxes to each over-fire air port. Each port will be located approximately ten to fifteen feet above the top burner row.

The purpose of this project is to reduce NOx emissions in order to comply with anticipated reductions in the station's air permit. OFA is one means to accomplish such reductions. OFA is a means of "extending" the combustion process to thereby reduce peak flame temperatures. Peak flame temperature is one of the variables which influence the amount of NOx produced in the combustion process.

Four Corners is already equipped with Low NOx Burners, and thereby our current NOx emissions are much lower than when Units 4 and 5 were first constructed 37 years ago. The new, recently issued Federal Air Implementation Plan (FIP) does not immediately require NOx reductions below the present levels. However, EPA is requiring Four Corners to conduct various studies aimed to explore what further reductions might be appropriate. We anticipate that these studies will conclude that some reduction is required. What is less clear is the level and timing of the initial reductions. Further reductions in subsequent years might also be required.

Based on the above, APS environmental experts have concluded that the probability of needing to install OFA over the next few years is high. We therefore have forecast the installation of OFA on Unit 5 in 2009 and on Unit 4 in 2010. The Coal Dynamic Classifier Project discussed in section 3 below is also included in our forecast, in anticipation that it will also be required to meet future NOX limits.

The OFA project cost estimate was generated by APS personnel assuming an appropriately sized OFA system that achieved a balance between maintaining Unit fuel efficiency and achieving NOx reductions. This expenditure is included in the forecast in anticipation that regulators will, in the near future, require the station to further reduce NOx emissions below present permitted levels.

2. <u>Overfire Air NOx Abatement Unit 4</u>

This $8.240 million dollar expenditure (of which SCE's share is $3.955 million) is essentially identical to the project discussed above for Unit 5, and is scheduled to be installed during the 2010 Unit 4 Major Overhaul. It will cost slightly more than the Unit 5 project due to one year of escalation of material and installation costs.

3. <u>Dynamic Classifier Modifications Unit 4</u>

This $6.420 million expenditure (of which SCE's share is $3.082 million) will install dynamic classifiers on each of the eight Unit 4 coal pulverizers during the 2010 Unit 4 major overhaul. This project will improve combustion performance and improve boiler efficiency, and reduce NOX emissions.

Coal fuel consumed by the large furnaces at Four Corners is reduced in size by large machines called mills or pulverizers. The ideal coal product delivered to the furnace by the mills is the consistency of fine powder comparable to baby powder. Consistent coal size is critical to the combustion process. In the current configuration, coal exiting the mills passes through a device that sorts the particles by size, and rejects those particles that are too large back into the mill for further pulverization. However, a small amount of these large particles are not captured by the current system, and are sent to the burners. The addition of a Dynamic Classifier will reduce the amount of large particles that are sent to the burners.

Excessively large particles increase NOx emissions, increase the incidence of large ash formations on the furnace walls, and cause boiler gas pass fouling and adverse affects to air pollution control scrubbers and particulate baghouses. This expenditure will install dynamic classifiers on each of the eight Unit 4 coal mills. Dynamic classifiers have been demonstrated to enhance the particle classification process, improve combustion resulting in less NOx emissions, improve plant fuel efficiency and improve air quality. A secondary benefit is reduced erosion wear on coal mill components and discharge piping in the form of abrasion, such as discussed earlier in the coal mill discharge piping replacement projects.

4. Dynamic Classifier Modifications Unit 5

This $6.613 million expenditure (of which SCE's share is $3.174 million) will install dynamic classifiers on each of the eight Unit 5 coal pulverizers during the 2011 Unit 5 extended minor overhaul.

This project is essentially the same project as described above for Unit 4. This project will improve combustion performance, improve boiler efficiency, and reduce NOX emissions as stated in the Unit 4 project described above.

5. SO2 Scrubber Controls Unit 5

This $4.939 million dollar capital expenditure (of which SCE's share is $2.371 million) is being implemented due to the new FIP. This expenditure is to replace the unreliable SO2 Scrubber Control System during the 2008 Unit 5 overhaul. The FIP requires SO2 removal be increased from the prior requirement of 72 percent to the new level of 88 percent (based on a 30-day average). APS began efforts to reduce SO2 pollution levels approximately two years ago in anticipation of the issuance of the FIP. APS conducted testing, and determined that we could comply with these reduced limits without requiring major capital expenditures on an entirely new SO2 pollution abatement system. However, APS technical and operating personnel determined that some process enhancements, including selective component upgrades such as controls systems replacement, would be needed.

Primarily, achieving this SO2 reduction requires that we increase our rate of lime injection. As discussed in Part I of this volume, sustaining this reduction will also require that we have better control of the abatement process, and that we increase the reliability of the abatement system equipment. We will have to spend more time and resources maintaining our lime injection nozzles, the 40 large slurry re-circulating pumps and 200 horsepower motors, and the system's many valves.

This particular capital expenditure is to replace the existing Four Corners Unit 5 SO2 scrubber control system that has become obsolete and unreliable. The existing control system will be replaced with ABB Automation's Symphony Distributed Control System (DCS), the same control system used on many other systems on Units 4 and 5. The new SO2 scrubber control system will be integrated with the existing plant DCS. APS plans to complete this expenditure during the 2008 overhaul.

The SO2 Scrubber system removes much of the SO2 pollution from the boiler flue gas before the flue gas is discharged to the atmosphere. The SO2 removal plant utilizes an absorption process that mixes flue gas with lime slurry to remove the SO2 from the flue gas. This process mixes concentrated lime slurry with flue gas that reacts with the lime. The SO2 remains with the lime slurry and the cleaned flue gas is discharged out the lined stack.

The absorption process includes three major process flows: the flue gas flow path through the absorber; the lime slurry flow that is re-circulated through or added to the absorber; and the water flow to the absorber from the makeup water system and the process liquor system. Each of these three process flows currently utilize a different control system that must work together for proper system operation. The SO2 removal system is controlled from the SO2 control room. The system is normally controlled in automatic mode, however, manual control capability is provided.

The existing SO2 removal control systems include a Bailey 820 system and a Modicon 984 Programmable Logic Controller (PLC). These systems are more than 20-years old, are deteriorating, and the major components are no longer supported by the equipment manufacturers. As with most control technology, obsolescence increases as technology advances. In this case, repair parts can no longer be purchased or manufactured. The programming and backup equipment is also very old, and when it fails, it is difficult and time consuming to restore the programming code. Loss of the control system requires operator intervention and possible load curtailments. In this situation, load curtailments are necessary because the scrubbing process does not operate at its optimum efficiency when in manual control.

As stated, APS plans to replace the system with equipment that will be integrated with the DCS. This will provide an enhanced level of reliability and better coordinate operation of the scrubber with the generating unit. APS anticipates improvement in system diagnostics, system coordination, historical data storage/retrieval, and operator interface, including improved visibility of the scrubber process by the control room operator. Enhanced operator awareness will enable personnel to anticipate and address problems quickly. These improvements are necessary to sustain compliance with the new FIP. Risks of deferring this expenditure include exposure to load curtailments that occur when the stack flue gas cannot meet emission requirements due to reduced scrubber efficiency, and possible air quality violations resulting from malfunction of the stack gas scrubber.

6. SO2 Scrubber Controls Unit 4

This $2.333 million expenditure (of which SCE's share is $1.120 million) is similar to that described above for Unit 5. However, because certain components on Unit 4 have been previously upgraded, the scope of work is somewhat less.

This project will be implemented during the Unit 4 2010 major overhaul.

7. **Scrubber Outlet Duct Liner Replacement Unit 4**

This $6.367 million expenditure (of which SCE's share is $3.056 million) replaces the corrosion resistant liner for the Unit 4 flue gas outlet duct. This work will be done during the 2010 Unit 4 overhaul. The pollution control equipment at Four Corners causes regions of corrosive moisture accumulation in the boiler flue gas outlet ducts. The structure and encasement of the ducting is constructed of carbon steel and is subject to corrosive attack if not protected. To provide protection, the duct work is fitted with a liner of corrosion resistant material. The existing liner was installed in 1989 and has been in service for approximately 18 years. Over the operational life of the liner, it has also been subject to the erosive effects of ash and other solid particles in the boiler flue gas. The result of this very severe service is the gradual development of small holes (pin holes) in the liner which expose the underlying carbon steel duct to the corrosive constituents of the flue gas. This rapidly spreading corrosion is difficult to detect because it is hidden under the liner when inspecting the inside of the duct, and is hidden by the exterior surface of the duct work when inspecting the outside of the duct. It is typically not discovered until it damages a very large area. The costs to repair this damage are high and the work requires the unit to be out of service. When large areas of the liner are damaged and can no longer be effectively repaired, replacement of the liner is needed. Replacement of the duct liner requires an outage of several weeks and must therefore be scheduled in conjunction with a unit overhaul.

Maintenance of the SO2 scrubber system, including the duct liner, is required or the scrubber would have to be removed from service. Our environmental permits require the scrubber to be operational, or we would exceed our SO2 limit and would be required to shut down the plant.

8. **Baghouse Dust Suppression System Installation Unit 4 and 5**

This $2.356 million expenditure (of which SCE's share is $1.131 million) is being implemented in 2008 in order to comply with the FIP which includes new limits on the plant's fugitive air emissions. Fugitive emissions are small particles (e.g., dust or soot) that get entrained into the air, reduce visibility, and perhaps more importantly, can potentially cause health problems.[16] These particles

[16] Fugitive emissions (in contrast to "stack" emissions) are air pollution that originates from any area of the plant other than the boiler exit gas stacks.

can be carried significant distances by the wind. This expenditure is required to assure compliance with the new limits.

This expenditure is needed to design, fabricate and install a recirculation ductwork system for the existing Baghouse. The Baghouse is part of the system used on each unit to remove ash from the combustion flue gases, so this ash is not released into the atmosphere from the boiler stacks. The Baghouse consists of 48 "compartments" on each unit. Each compartment contains 414 fabric filter elements ("bags") through which the flue gas passes. These bags capture much of the ash and are periodically automatically cleaned (i.e. emptied). The compartmentalized Baghouse system allows cleaning and maintenance to be performed on up to two compartments at a time, while the other compartments remain in service. This maintenance includes replacing bags which rip or tear while in service, repairing reversing air valves and performing inspections. If the baghouse is not maintained the unit would experience high opacity resulting in violation of the station air permit.[17]

When compartments are to be taken out of service for maintenance (i.e. while the unit is on line and the other baghouse compartments are in service) they must be ventilated before employees are allowed to enter the compartment. This venting can create significant fugitive dust. Modifications must be made to allow on-line maintenance of baghouse compartments to continue into the future while also meeting the plants new fugitive dust emissions limits. The purpose of this project is to install ductwork, piping and valves on the discharge side of the existing Baghouse ventilation fans, and route the new ductwork to the inlet sides of the boiler exit gas passages. This way, when compartments are ventilated, the ventilation discharge air is routed back to the boiler exit gas ducting instead of to the atmosphere. The exit gas, along with this additional fugitive dust discharged into the exit gas, will then flow to the adjacent on-line Baghouse compartments. This new ducting will thereby allow the venting discharge dust to be routed to an on-line compartment rather than to the atmosphere. This will allow the

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17 Stack Opacity monitoring is the measure of particulate matter (e.g. dry fly-ash particulates) to a precise value with the objective of maintaining compliance with regulatory emissions laws and standards regarding maximum allowable particulates released into the atmosphere from a coal burning plant. Stack opacity excursions occur when operations processes are upset resulting in more particulates exiting the exhaust stack than permissible by air quality regulations. This excursion can result in an environmental permit violation and carry substantial fines and in extreme cases penalties.

station to control fugitive dust emissions associated with baghouse operations and maintenance activities.

This expenditure is required to meet the new FIP.

9. <u>Baghouse Turning Vanes Replacement Unit 5</u>

This $2.204 million expenditure (of which SCE's share is $1.058 million) replaces Unit 5 Baghouse Turning Vanes which redirect furnace exit gas flow at the duct work transition (bends) areas. Due to the erosive nature of the fly ash laden flue gas, the Baghouse turning vanes are at the end of their useful lives and can no longer be repaired. The new turning vane configuration and design will incorporate metal sprayed alloys to reduce the potential of this erosion being an issue in the future. The new vanes will be installed during the Unit 5 2008 overhaul.

If the turning vanes are not replaced, there is a high risk the vanes will experience catastrophic failure on-line, which would result in the station exceeding opacity limits. Such a failure would also result in pluggage of the flue gas paths and cause excessive erosion on the duct work. It is estimated that to clear the duct work from such a blockage caused by a collapse of the old turning vanes would result in a minimum five day unit outage.

Maintenance of the Baghouse and other pollution control components is needed to meet our stack gas particulate and opacity emissions limits. We can not operate the plant without this equipment being operational, as we would not be able to meet our air permit limits.

10. <u>Dry Ash Land Fill and Haul Road Units 4 and 5 - Phase 1</u>

This $7.554 million expenditure (of which SCE's share is $3.626 million) constructs an appropriately engineered land fill facility and haulage road for disposal of ash wastes generated by Units 4 and 5. Four Corners Units 4 and 5 produce large quantities of fly ash, bottom ash slag, and air pollution scrubber sludge as byproducts of combustion and flue gas conditioning. This material presents major challenges to the plant operator because of great volume of ash wastes, and the corrosiveness of the ash. This waste must be handled and stored in manner that meets all regulatory requirements. APS has disposed of these materials into the mined out coal pits and waste ponds for many years. Many of these formerly used disposal sites have either reached their storage capacity or have compromised linings and must be either refurbished or replaced.

The currently used land fill coal pits are located approximately 14 miles round trip from the Four Corners plant and this location is nearing capacity. A new properly designed land fill is required for future ash disposal. Deferral of this work presents risk of production curtailments because improper disposal of ash material is not an acceptable option. APS will design, engineer and construct a new ash land fill located approximately nine miles round trip from the plant. A new haulage road to the new land fill site is currently in initial construction phases and the associated costs are included as part of this project. This project will go into service in late 2007.

11. <u>Fly Ash Landfill - Phase 2</u>

Additional expansion of the new ash landfill discussed above will be needed by 2011. This expansion project is forecast to cost $5.000 million of which SCE's share is $2.400 million.

This Phase 2 Fly Ash Landfill expansion is required to increase the square footage of the Phase I landfill before 2012, based on the projected fill rates. The expansion will consist of utilizing bottom-ash for foundation berms, which will be constructed using a mix of dirty dry fly ash and clay. These new berms will elevate the containment levees around the landfill. This process of additional land fill phases in future years is expected to continue over the remaining life of the plant.

This environmentally driven project is scheduled to be completed by 2011 to coincide with the first phase land fill reaching capacity.

12. <u>Fly Ash Beneficiation Area Improvement Units 4 and 5</u>

This $2.500 million expenditure (of which SCE's share is $1.200 million) provides for a means of reducing our ash hauling costs and landfill costs. The Fly Ash Beneficiation Project provides for several new equipment modifications to our ash waste handling systems to increase our ability to handle and fill dump trucks with "clean" fly ash. This "clean" fly ash is a marketable by-product of the coal combustion process. The conveying system equipment additions, storage facility additions and relocation of this process to a larger section of real estate will allow us to process approximately double the amount of clean "sales grade" fly ash which can be recovered each year. Our Four Corners 2009

Test Year O&M forecast includes the $1.176 million per year additional revenue we expect to receive from with this increase in our clean ash sales.

This project also results in a modest reduction in the volume of fly ash previously discarded with other wastes and hauled to the Four Corners ash landfill. However, the savings of reduced ash hauling will be offset by the increased cost of the Ash Beneficiation Area operations and maintenance expense. Nevertheless, as indicated above, this project will pay for itself in less than two years based on the forecast increase in ash sales revenue. This revenue was included in our 2009 Test Year O&M forecast as discussed in Part I of this Volume.

This project will go into service in 2009. This project also helps minimize capital costs associated with landfill expansion, by reducing the volume of wastes requiring landfill disposal. This project also increases ash sale revenue.

13. Thickener Underflow To Lined Ash Impoundment Units 4 and 5

This $3.406 million expenditure (of which SCE's share is $1.635 million) will provide for installation of a new scrubber underflow thickener system to reduce the volume of wastes being transported to impoundment facilities. This project will go into service in 2007.

Four Corners utilizes scrubber equipment to reduce SO2 levels in the boiler flue gas. The scrubbing process produces a sulfate sludge byproduct that must be processed and handled in accordance with environmental requirements. Existing equipment used to process the sludge materials includes holding tanks, vacuum filters, pumping equipment, mixing equipment and the associated interconnecting piping and controls. Currently, the sludge is concentrated using this equipment, mixed with fly ash and trucked to the landfill. Mixing it with fly ash is necessary to raise its density sufficiently such that it can be land-filled rather than disposed of in a lined pond. Land-filling of dry waste material is generally less costly than disposing of wet slurry wastes.

Consistent with the various projects discussed above, APS examined alternatives for processing scrubber sludge because the existing landfill is approaching maximum capacity. Furthermore, as discussed earlier, the new FIP requires greater SO2 reductions than previously allowed. This required increasing our lime feed rate for the SO2 scrubbing process, which in turn generates a substantial increase in the volume of sludge wastes. APS has determined that installation of a scrubber sludge thickener system will provide the most economic alternative for current and future sludge processing requirements. Thickeners are a proven technology which utilize a polymer additive to chemically concentrate the solid materials contained in the sludge.

The thickened sludge will then be conveyed to a lined impoundment pond. As the sludge arrives at the pond it will be filtered and decanted. The removed water will be stored in a separate pond, and then recycled back to the SO2 injection system process as needed. The waste material remaining after the filter and decant processes will remain in the ash waste pond. As the waste product will contain considerably less water than the existing process, the pond can hold more wastes. Therefore, in this case the use of a lined pond is a lower cost alternative to the present method of mixing the underflow waste with ash and hauling it to the landfill.

The alternative to a chemical thickener system is a simple expansion of the existing sludge treatment process, continued use of fly ash as a binding agent, transportation of the material by truck or conveyor, and use of ash landfill space for disposal. Expansion would be needed because of the higher level of underflow wastes we are generating in achieving the lower SO2 reductions required by the FIP. This expansion alternative would substantially increase the annual O&M costs of processing the sludge. By proceeding forward with this project instead of a simple expansion, future O&M costs will be approximately equal to our historic costs for processing and disposing of this SO2 scrubber sludge.

14. <u>5268 Foot Lift Lined Ash Impoundment Units 4 and 5</u>

This is $3.529 million expenditure (of which SCE's share is $1.694 million) is for the construction of the lined pond for the wet slurry wastes described above. As discussed in the above project, modifications will be made to the SO2 scrubber slurry processing system. These modifications eliminate the use of dry fly ash for scrubber waste processing, so that this fly ash can instead be sold. These modifications also reduce the size of the required landfill for dry wastes. However, these modifications will require that the station's wet waste impoundment capacity be expanded. In addition to the scrubber slurry wet wastes, other wet waste include various ash, slag, and other scrubbing equipment wastes.

For these reasons, APS needs to construct a new lined impoundment pond. The new impoundment will cover 71 acres of land, and will be located on terrain which is at an elevation of 5268 feet above sea level. This new "5268 Foot Lift" Lined Ash Impoundment will be placed in service in 2011. It will collect waste ash from Units 4 and 5 and serve as replacement to the existing impoundment pond currently reaching maximum capacity.

This project will also include construction of a separate water pond at a lower elevation. As described for the above project, this lower elevation pond will collect water which is separated from the wet slurry underflow deposited into the 5268 Foot Lift Impoundment. This project includes design, engineering, appropriate site preparation, and construction of the impoundment and the waste water pond, and installation of appropriate lining materials.

This work is forecast to be completed in 2011. This project is environmentally driven in that the station's waste dry landfill, wet impoundment, and waste water pond systems must be refurbished as they are all nearing capacity. Proper disposal of these waste streams is required for plant power production operations to continue into the future.

15. <u>Waste Process System Improvements Unit 4 and 5</u>

This $2.500 million expenditure (of which SCE's share is $1.200 million) replaces the Four Corners Units 4 and 5 waste processing system (WPS). As is the case with the SO2 scrubber control system, this equipment has become obsolete and unreliable. APS will replace the existing control system with a microprocessor-based distributed control system (DCS) and will integrate the control process into the plant DCS for Units 4 and 5.

The WPS is made up of four systems: the filtrate and seal water return system; the thickener slurry overflow feed process liquor system; the fly ash reject feed system; and the waste mixing system. The WPS receives rejected non-sales grade fly ash from the fly ash transfer system and mixes these waste products in a three-train process. The final mixed product is acceptable to be placed in the dry landfill. This mixing and dry land filling process will continue to be used for certain wet waste streams, even after start-up of the above projects which change our process for handling wet scrubber waste slurry.

The WPS is centrally controlled from a local control panel using programmable controllers and an analog controller. The control system includes a combination of Modicon 484 programmable controllers and Bailey 820 analog controllers. The existing control system is obsolete and is no longer supported by the manufacturer. Spare parts are unavailable and cannot be purchased or remanufactured. Additionally, APS has one remaining programming/backup tool, and if this tool were to fail, there is no way to backup or reload the control program, which is required for the system's operation.

Upon failure of the control system, the WPS system will shutdown, and there is no "manual" mode for interim operation of the system due to the complexity of the control dynamics. In such an event, the final waste product will fail to meet disposal requirements and will have to be held on site. The on-site holding capacity is only good for 24 hours, after which time unit generation must be curtailed to avoid further production of waste products, until the WPS can again be made operational. Under severe circumstances, APS estimates that one to two weeks will be required to build and install a functionally equivalent emergency replacement part and return the WPS to operation.

The new replacement system will be integrated with the plant DCS, giving it the same level of maintainability, diagnostic capability, and operational flexibility as the primary plant control systems. Centralized monitoring, historical data storage/retrieval, and integration with the power and waste generation controls will enhance the overall WPS performance. This expenditure is being undertaken primarily to resolve control equipment obsolescence and reliability problems which will result in inability to properly process and dispose of power generation waste materials. If not corrected, we have an environmental risk of producing waste that is not suitable for landfill, in the event of control system failure. Economic risks associated with the deferral of this expenditure include risk of generation curtailment due to control system failure and substantial future O&M cost increases if the failed control system has to be replaced on an emergency basis.

This project is expected to be completed in 2009. This project is required to maintain environmental compliance.

16. Intake Structure Modifications Units 4 and 5

This $3.000 million expenditure (of which SCE's share is $1.440 million) will increase the area of the plant's cooling water intake structure inlet screens, as needed to slow water flow velocity to below the new 0.5 feet per second regulatory limit (EPA Regulation 316B Phase II). This new regulation requires protection of Morgan Lake fish from high water flows at the plant intake areas. Morgan Lake is the source of cooling water for the plant. This project will reduce the risk to fish of being entrained and killed in the plant's cooling water system.

This work will be completed in 2008. This project is environmentally driven and is required for the continued compliance of the Four Corners Power Plant with EPA regulations.

17. River Station 316B Regulation Modifications

This $3.000 million expenditure (of which SCE's share is $1.043 million) is required to comply with EPA Regulation 316-B, Phase III specific to protecting fish inhabiting areas near the San Juan River intake water system. Water drawn through this intake is then conveyed to Morgan lake.

The scope and purpose of this project is to increase the area of the process water inlet at the river area screens to slow the water flow to below 0.5 feet per second now required by EPA regulations. This work will be completed in 2011.

18. Environmental Projects less than $1 Million (SCE share)

Table XII-6 lists the Environmental Projects which are less than $1 million each, SCE share. These total $12.071 million of which SCE's share is $5.453 million. These account for 3 percent of our total capital forecast.

Table XII-6
Environmental Projects Less Than $1 Million Each
($1,000 – Nominal)

ENVIRONMENTAL PROJECTS < $1 MILLION ($1,000 - Nominal)	In Service	100% Total	SCE Share Fraction	SCE Share $1,000
AIR POLLUTION COMPLIANCE				
18- 1 MERCURY CEMS, U 4&5	2008	1,033	0.4800	496
18- 2 SO2 PROCESS IMPROVEMENTS, U 4&5	2011	1,000	0.4800	480
18- 3 STACK FLOW MEASUREMENT REPL, U 4&5	2007	672	0.4800	322
18- 4 BAGHOUSE MAINTENANCE BLDG, U 4&5	2008	373	0.4800	179
18- 5 ABSORBER MODULE BLOW DOWN MODIF, U4	2008	267	0.4800	128
18- 6 ABSORBER MODULE BLOW DOWN MODIF, U5	2010	267	0.4800	128
18- 7 U4&5 S02 CONTROL BUILDING REMODEL	2011	250	0.3476	87
18- 8 DEW POINT MONITORING EQUIP REPL, U 4&5	2009	133	0.4800	64
18- 9 EPA EDR SOFTWARE UPGRADE	2007	57	0.3476	20
18- 10 HUMATE SILO & SLAKING EQUIP, U 4&5	2009	1,000	0.4800	480
SUB-TOTAL		5,052		2,384
SOLID WASTE COMPLIANCE				
18- 11 WASTE PROCESSING CONTROLS REPL, U 4&5	2007	1,676	0.4800	804
18- 12 ASH POND 6 CLOSURES	annual	140	0.3476	48
SUB-TOTAL		1,815		853
WASTE WATER DISCHARGE				
18- 13 5258' LIFT LINED ASH IMPOUNDMENT, U 4&5	2009	1,861	0.4800	893
18- 14 THICKENER AUTOMATIC POLYMER INJECT, U 4&5	2009	200	0.4800	96
18- 15 HYDROBIN AREA UPGRADE, U 4&5	2009	800	0.4800	384
18- 16 NPDES HAUL ACCESS ROAD	2008	791	0.3476	275
18- 17 POND CHLORIDES CONTROL UPGRADES	2008	748	0.3476	260
18- 18 NPDES DECANT CELL UPGRADES	2010	593	0.3476	206
18- 19 500KV YARD STEP-UP TRANSF OIL BERM, U 4&5	2008	120	0.4800	58
18- 20 SPCC CONTAIN OF OIL TANKS, U 4&5	2007	91	0.4800	44
SUB-TOTAL		5,204		2,216
TOTAL ENVIRONMENTAL PROJECTS < $1 MILLION EACH		12,071		5,453

These projects are needed to address various requirements related to air emissions, waste water discharge regulations and permits, and solid waste disposal. More details on each of these projects can be found in the workpapers to this volume.

D. <u>Safety</u>

Table XII-7 lists the Safety Projects which we expect to complete during 2007 through 2011. These total $8.967 million of which SCE's share is $3.471 million.

Table XII-7
Safety Projects
($1,000 – Nominal)

SAFETY PROJECTS ($1,000 - Nominal)	In Service	100% Total	SCE Share Fraction	SCE Share $1,000
1 PLANT FIRE WTR UNDGRND PIPE REPL	annual	3,000	0.3476	1,043
2 POTABLE WATER SYSTEM REPL	2011	3,000	0.3476	1,043
SUB-TOTAL PROJECTS > $1 MILLION EACH		6,000		2,086
3 GSU & AUX XFMR FIRE WALL/OIL CONTAIN, U 4&5	2007	1,589	0.4800	763
4 HIGH ENERGY PIPING, U 4	2010	1,000	0.4800	480
5 LAYDOWN YARD LIGHTING	2007	289	0.3476	100
6 COLD REHEAT #2 PIPE SUPPORT, U 5	2008	89	0.4800	43
SUB-TOTAL PROJECTS < $1 MILLION EACH		2,967		1,386
TOTAL SAFETY PROJECTS		8,967		3,471

1. Plant Firewater Underground Piping Replacement

This $3.000 million dollar expenditure (of which SCE's share is $1.043 million) replaces approximately 6500 feet of the firewater system piping that has become unreliable and is failing. The complete scope of work will require the excavating for new lines, replacements of valves and post indicators, installation of new concrete anchor blocks, and replacement of asphalt and concrete decks. This project work will begin in 2008 with engineering and materials procurement and be performed in stages over a three year period ending in 2010.

The firewater piping system surrounds the station and is arranged in a series of interconnected loops. Each interconnected loop is designed with isolation valves to ensure continuity of supply in the event a section must be isolated. The fire water system is supplied from the Four Corners plant lake commonly referred to as Morgan Lake. The fire water system is pressurized by two diesel driven fire pumps, one EMD (Electric Motor Driven) fire pump and one EMD Jockey pump, all of which are located on the East side of the Unit 4 and 5 Discharge Canal. Additionally, one EMD jockey pump is located on the Units 1, 2 and 3 Intake structure, one EMD Jockey pump and one booster pump is located at the S02 Fire Pump House, all of which are available as a back-up to support the primary system needed. This overall system dates from original construction. System reliability is a NFPA (National Fire Protection Association) and local fire ordinance requirement.

In the past five years, Four Corners has experienced three large pipe failures on the fire water protection system underground piping. One of these failures flooded the reserve auxiliary buss duct, causing the failure of that system and simultaneous forced outages on both Unit 4 and Unit 5, resulting in significant megawatt generation losses. Each failure has averaged four days to repair. The pipe failures have been throughout the system and not centralized to any particular area. Excavation of the pipe failures has found large pieces completely broken away from the pipe allowing full pipe flow through the failure.

The conclusion reached by the analysis is that the pipe failures are the result of graphitic corrosion (sometimes also referred to as graphitization). Graphitic corrosion is defined as the deterioration of gray cast iron in which the metallic constituents are selectively leached or converted to corrosion products leaving the graphite intact. This failure mechanism is not uncommon for gray cast iron pipe. The piping system is unreliable and should be replaced.

Risks associated with deferral of this expenditure include: (1) failure in one loop can result in temporary reduced pressure in others; (2) continued degradation of the firewater system will result in increased repair costs and higher risk of equipment damage; (3) violation of regulatory requirements that the fire water system be maintained in-service at all times. Failure to replace the system will result in increased O&M expenditures to perform temporary installations to bypass failed sections.

This expenditure is required to maintain safety and regulatory compliance.

2. <u>Potable Water System Replacement</u>

This $3.000 million expenditure (of which SCE's share is $1.043 million) provides improved potable water quality and replaces piping as necessary to reduce future failures. This project is needed based on the results of a recent inspection and subsequent testing of the Four Corners potable water system. Testing identified the existing water treatment equipment is not capable of meeting the long-term needs of the station in compliance with drinking water standards. This work will be completed in 2011.

3. Safety Projects Less than $1 Million (SCE share)

Table XII-7 presented above also shows the four Safety Projects which each cost less than $1 million each, SCE share. These projects address safety needs associated with piping, transformer oil spill containment, and plant lighting. These total $2.967 million of which SCE's share is $1.386 million. Additional details for these projects can be found in the workpapers to this volume.

XIII.

MOHAVE DECOMMISSIONING CAPITAL FORECAST

A. Introduction

SCE is currently working with the other Mohave Generating Station owners to disposition the plant. The plant stopped generating power on December 31, 2005, consistent with the terms of the Consent Decree.[18] Our discussion contained in Part I of this Volume (Coal O&M) covers the following areas:

- The circumstances that required the Mohave plant to cease production.
- Activities SCE and the other owners took leading up to the December 31, 2005, and actions taken since that date.
- The Mohave Balancing Account regulatory treatment for costs incurred at Mohave since that date, and our proposal to continue with that regulatory treatment for this Rate Case timeframe.
- Our conclusion that it is prudent to assume that plant decommissioning will be required during this Rate Case period.
- Our forecast that we will rapidly proceed with decommissioning, once a plan is finalized.
- Our 2009 Test Year O&M cost forecast for site management activities anticipated to be required during and following decommissioning.

This chapter addresses our capital cost forecast for decommissioning the Mohave Generating Station. In summary, the scope of work of our forecast decommissioning includes removal of essentially all structures, except for the switchyard and SCE telecommunications equipment. As the switchyard control equipment and instrumentation is currently located in the power plant control room, this switchyard control equipment will have to be relocated (i.e., replaced with new equipment in a new building constructed for the purpose) as part of the generating station decommissioning.

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[18] *See* Footnote 31, Chapter VIII,B., above.

While the station owners have not yet made a decision to proceed with decommissioning, and have not yet agreed to a decommissioning scope of work, our current decommissioning forecast assumes we will remove essentially all generating station property improvements. Our forecast assumes that the only structures and equipment that will remain following decommissioning will be that needed to operate and monitor the site's ground water pumps and wells, and evaporation pond system. The plant structures to be removed during decommissioning include:

- The Unit 1 and 2 power block equipment, including boilers, stack, control room, turbine-generators, transformers, electrical conductors and poles, foundations, and all related equipment.
- Coal day tanks, slurry lines, and all related structures.
- All ash handling equipment, foundations structures and paving.
- All slurry water, wastewater, cooling tower water and boiler make-up water treatment equipment and water recycling equipment.
- All major underground structures.
- Cooling towers, canals and all related connecting equipment.
- All auxiliary equipment and utilities related to the power and all other structures, including fire water systems, compressed air systems, sanitary systems and the like.
- Visitor center, training center, warehouse, shops, automotive garage, parking structures, and all related paving, interior fencing and landscaping.
- All lighting, utility services, and related plumbing and electrical equipment except that remaining to service the guard house, and main entry driveway and property front gate.

Our forecast decommissioning work scope also includes preliminary restoration (i.e., major grading) of coal storage ponds, retired wastewater evaporation ponds, and similar areas of the property. In addition, the work includes performing all necessary consolidations, modifications and relocations of existing plumbing and electrical systems to facilitate:

- site security following decommissioning (*i.e.*, access gates, cameras, fencing and perimeter lighting, *etc.*), and
- the ongoing operations and maintenance of the switchyard, telecommunications equipment, and the site groundwater pumping, monitoring and evaporation systems.

Under the terms of our Nevada water discharge permit, SCE is prohibited from discharging any water off the site. Therefore, water pumped from the ground for monitoring and treatment is sent to on-site evaporation ponds. As this water evaporates, dissolved or suspended solids that are present in this water are left behind in the pond as a residue. This residue must then be periodically removed from the pond and properly disposed. These groundwater activities will continue as decommissioning work starts. We do not yet know the date when these groundwater activities will cease. These activities will continue until the station owners and water quality regulators agree that no further monitoring or remediation is needed.

B. Cost Estimate of Decommissioning

As presented and approved in our 2006 GRC, we forecast the cost to decommission Mohave is $101 million, of which SCE's share is $57 million. Since our 2006 GRC proceeding, SCE has conducted another study to forecast the cost to decommission Mohave. This study concluded that decommissioning would cost $100 million, of which SCE's share is $56 million. This updated figure is used in our Results of Operations calculations, as appropriate. Through operation of the Mohave Balancing Accounting, ultimately SCE will only collect in rates the final actual cost of the decommissioning.

Arcadis G&M Inc. (Arcadis) was selected by SCE to perform the updated Mohave decommissioning study, which they began in September 2006. Their updated draft decommissioning plan was delivered by them to SCE in mid-November 2006. The following is a brief summary of this study. A full summary of the Arcadis study is included in the work papers to this volume.

The Arcadis study provides a technical approach, detailed schedule and cost estimates for the demolition of Mohave's physical and operational features, and the regulated closure of permitted units/features over the longer term once it is appropriate to do so (e.g., evaporation ponds, underground storage tanks, groundwater monitoring wells, etc.). The onsite demolition includes abatement of asbestos and hazardous materials and general removal of plant features to a depth of three feet below grade. The site would then be graded to match surrounding contours. Off site demolition includes the River Pump House, abandonment and slurry fill of associated water lines, two air-monitoring stations, and the abandonment and slurry fill of the coal slurry line from the station to the isolation value box located across the Colorado River.

The plan breaks the site into 13 zones to allow for easy scope adjustments. For example, if it is later determined that the Training Center at Mohave can be sold as a stand-alone structure, then the Training Center could be removed from the decommissioning scope, thereby reducing the project cost.

Arcadis estimates that the majority of the closure activities can be accomplished within 26 months from a decision to proceed. However, additional time will be required to install the new switchyard controls and building. Therefore, the total project could last approximately three years. Assuming a decision is reached to proceed with decommissioning in mid-2007 and the work immediately begins, then decommissioning work would conclude at some point between late-2009 and 2011.

The Arcadis study produced a 100% share cost forecast of $64.952 million (before contingency and owner's costs) to decommission the 13 identified work zones. However, consistent with the contracted workscope for the study, the Arcadis forecast does not include certain items. As described above and in Part I, the existing Mohave switchyard must remain in place and operational. This will require relocation of the switchyard controls out of the Mohave power plant control room, and into a new structure dedicated for the switchyard. A preliminary cost estimate by SCE engineering staff indicates this relocation work would cost approximately $5.538 million (100% Share, before contingency and owner's costs). Telecommunications equipment must also be assessed to determine if relocation is required; and if so, it must be determined whether existing equipment can be moved or if new equipment must be purchased for installation in a new location.

Our forecast further includes an appropriate level of contingency (*i.e.*, 30%),[19] and owner's costs to plan and oversee the decommissioning project. Owner's costs include gaining any needed regulatory approvals, assisting in identifying all underground structures for physical removal, assuring that all contractor invoices are proper and appropriate for payment, and similar tasks. We forecast these SCE management, engineering, permitting and contract oversight costs at 5% of the total project costs, which equals $3.468 million (100% Share).

Including the above items, our Mohave decommissioning cost estimate is $99.588 million (100% Share) as follows in Table XIII-8:

Table XIII-8
Mohave Decommissioning
($ Million - 100% Share - $2006)

Mohave Decommissioning 100% Share - $1,000 - Nominal	
Demolition Base Scope for 13 Zones	64,952
Switchyard Separation Costs	5,538
Escalation (3.5%)	2,467
Owner Costs (5%)	3,648
Sub-Total	76,605
Contingency (30%)	22,983
TOTAL	99,588
SCE Share (56%)	55,769

The accounting treatment for the direct decommissioning expenditure, and for the switchyard and telecommunications equipment relocation (and replacement) work required because of the decommissioning, is discussed in our Results of Operations testimony.

C. Site Management Capital Needs at Mohave After Decommissioning

As discussed in Part 1 (Coal O&M), SCE anticipates that SCE will continue to own 56 percent of the decommissioned Mohave site, and that ongoing management of the site will be required following decommissioning. These site management tasks will include operation and

[19] Inclusion of a 30% contingency is appropriate as only limited engineering work has been completed to date for the Mohave Decommissioning Project. This project is in the Preliminary Engineering phase. The US Department of Energy guidance to DOE project cost estimators and project managers for DOE projects in the preliminary phase is to include a contingency of 30%-50% of the project's estimated costs, per Figure 11-1, Chapter 11 – Contingency, DOE G-430.1-1, the companion guide to DOE Order 5700.2 – Cost Estimating, Analysis and Standardization.

maintenance of the groundwater wells and pumps, and the related evaporation pond system. Certain of these groundwater well and pond maintenance activities have recorded as capital additions in the past, consistent with FERC accounting guidelines. Specifically, the replacement of an entire well and pump, or the replacement of an evaporation pond liner, is considered a capital expenditure.

Therefore, our GRC capital forecast for Mohave includes approximately $0.2 million per year for 2009 through 2011 for such capital needs related to site management, of which SCE's share is $0.100 million per year. Inclusion of this very modest capital expenditure forecast in this proceeding is appropriate given that capital needs could arise at Mohave during 2009 through 2011. By comparison, we recorded $0.339 million (SCE Share) during 2006 for groundwater well replacement capital expenditures at Mohave during 2006.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF GEORGE F. BUTTS

Q. Please state your name and business address for the record.

A. My name is George F. Butts, and my business address is 300 North Lone Hill Avenue, San Dimas, California 91773.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am a Project Manager in the Power Production Department Administrative Staff Group. My primary responsibilities are the development of O&M FERC Account expense data for the Power Production Department General Rate Case effort, and administrative, budget, and accounting issues relating to the Power Production Department.

Q. Briefly describe your educational and professional background.

A. I have an Associate Degree in business administration and a certificate in Industrial Supervision. I have been with SCE for 33 years and have served in the former Transmission/Substation Division, Steam Generation Division, and for the last 25 years in the Administrative Staff of the Power Production Department and its predecessor, the Power Supply Department.

I sponsored Exhibit 16 Coal O&M, Chapters IV and V, and Exhibit 18 Hydroelectric Generation O&M Chapter V in SCE's 2003 General Rate Case. I also sponsored Exhibit 4, Chapters VI through VIII of Electric Power Steam And Other Generation in SCE's 1995 Test Year General Rate Case. Before that, I was the primary author of testimony, estimates and other information for Steam, Hydro, Other Production, Transmission and some Distribution and A&G O&M expense estimates in Edison's 1985, 1988, and 1992 Test Year General Rate Cases and also participated in the 1979, 1981 and 1983 Test Year cases.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of Exhibit SCE-02, Volume 7 entitled *Generation Coal Operation & Maintenance and Coal Capital Expenditures* as identified in the Tables of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF PAUL F. PHELAN

Q. Please state your name and business address for the record.

A. My name is Paul F. Phelan, and my business address is 300 N. Lone Hill, San Dimas, CA 91773.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am presently the Manager of the Power Production Department, Engineering & Technical Services. I have management responsibility for the planning, cost, schedule and quality of projects and providing engineering and technical support for the Power Production Department, and other Business Units within SCE.

Q. Briefly describe your educational and professional background.

A. I have a Bachelor of Science degree in Mechanical Engineering from the University of Arizona in Tucson, and a Bachelor of Science degree in Metallurgical Engineering from the University of Texas at El Paso.

Prior to my current position, I have held various management and engineering positions within Edison in the fossil generation area.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of Exhibit SCE-02, Volume 7 entitled *Generation Coal Operation & Maintenance and Coal Capital Expenditures* as identified in the Tables of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF THOMAS G. WARE

Q. Please state your name and business address for the record.

A. My name is Thomas G. Ware, and my business address is 300 N. Lone Hill Ave., San Dimas, California.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am presently a Manager in the Business Planning & Development section of the SCE Power Production Department. The Power Production Department is responsible for operations, maintenance and capital improvements of SCE's fossil-fueled and hydroelectric power plants. My duties include coordinating the preparation of the department's annual business plan. I also assist with the oversight of SCE's share of the Four Corners Generating Station. My other duties include management responsibility for the department's portion of the General Rate Case, ERRA and other regulatory filings, and facilitating departmental compliance with regulatory requirements governing power plant reliability and similar issues.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Chemical Engineering from the California State Polytechnic University at Pomona, and am a registered professional Mechanical Engineer in California. Prior to my current position, I held various management and engineering positions within Edison over approximately the past twenty-five years, primarily in the power generation area. These prior positions included Lead Engineer of the Alamitos Generating Station, Senior Engineer in the Power Production Engineering & Construction division, Production Manager of the Redondo Generating Station, and Engineering & Construction Manager of the Edison Pipeline & Terminal Company (a former division of SCE).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of SCE-02, Vol. 7, Coal Operation and Maintenance Expenses, and Coal Capital Expenditures, of SCE's 2009 General Rate Case application.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Appendix B

Four Corners Capital Forecast

FOUR CORNERS CAPITAL FORECAST								Overhauls:					
Updated July 1, 2007					100%			Unit 4:	Minor (S)			Major (S)	
		Work		In	Share	SCE	SCE	Unit 5:		Major (S)			Minor (S)
	id	Order	Capital Project Description	Service	Total	Share	Total	Prior	2007	2008	2009	2010	2011
	RELIABILITY												
	1	06-08	HP TURBINE & CONTROLS REPL, U 5	2008	15,104	0.4800	7,250	1,010	3,497	2,743	0	0	0
	2	07-05R0	HP TURBINE & CONTROLS REPL, U 4	2010	16,231	0.4800	7,791	153	60	832	3,447	3,299	0
	3	PWEE	MINOR OVERHAUL TURB REPAIRS, U 5	2011	6,534	0.4800	3,136	0	0	0	0	0	3,136
	4	PWEE	HP GENERATOR FIELD REWIND, U 4	2010	2,185	0.4800	1,049	0	0	0	384	665	0
	5	06-05	LOWER BOILER REPLACEMENT, U 5	2008	18,495	0.4800	8,878	1,572	2,240	5,066	0	0	0
	6	06-06	PENDANT RH & OUTLET HEADER REPL, U 5	2008	14,581	0.4800	6,999	356	2,627	4,016	0	0	0
	7	07-04R0	PENDANT RH & OUTLET HEADER REPL, U 4	2010	18,981	0.4800	9,111	0	38	178	4,020	4,874	0
	9	06-07	2ND STAGE PENDANT SUPHTR REPL, U 5	2008	11,187	0.4800	5,370	353	2,183	2,834	0	0	0
	8	PWEE	1ST STAGE PENDANT SUPHTR REPL, U 5	2011	13,320	0.4800	6,394	0	0	10	384	3,072	2,928
	10	07-06R0	2ND STAGE PENDANT SUPHTR REPL, U 4	2010	14,081	0.4800	6,759	0	30	183	3,305	3,240	0
	11	PWEE	HORIZONTAL REHEAT BANK REPL, U 5	2011	6,310	0.4800	3,029	0	0	5	144	960	1,920
	12	PWEE	BOILER NOSE REPLACEMENT, U 4	2010	4,000	0.4800	1,920	0	0	48	912	960	0
	13	PWEE	BOILER NOSE REPLACEMENT, U 5	2011	4,190	0.4800	2,011	0	0	2	46	912	1,051
	14	05-04R1	MAIN FLAME SCANNER UPGRADE, U 5	2008	2,379	0.4800	1,142	137	621	384	0	0	0
	15	PWEE	AIR PREHEATER H/C BASKET REPL, U 4	2010	2,180	0.4800	1,046	0	0	0	384	662	0
	16	07-08	COAL PIPE REPL, U 5	2008	4,000	0.4800	1,920	1	864	1,056	0	0	0
	17	PWEE	COAL PIPE REPL, U 4	2010	8,867	0.4800	4,256	0	0	0	1,296	2,960	0
	18	PWEE	HP FEEDWATER HEATER REPL, U 4	2010	4,000	0.4800	1,920	0	0	0	720	1,200	0
	19	PWEE	PULVERIZER CAPACITY UPGRADE, U 4	2010	4,000	0.4800	1,920	0	0	0	96	1,824	0
	20	05-13	GSU TRANSFORMER T633 & T634 REPL, U 5	2008	3,837	0.4800	1,842	353	1,018	470	0	0	0
	21	06-09R1	GSU TRANSFORMER T631 REPL, U 4	2008	3,186	0.4800	1,529	163	1,040	326	0	0	0
	22	PWEE	GSU TRANSFORMER T629 REPL, U 4	2010	3,933	0.4800	1,888	0	0	16	272	1,600	0
	23	PWEE	UNDERGROUND CABLE REPLACEMENTS	annual	10,000	0.4800	4,800	0	0	1,200	1,200	1,200	1,200
	24	PWEE	PLANT PERIMETER SECURITY UPGRADE	2010	4,000	0.3476	1,390	0	0	0	174	1,217	0
	25	PWEE	COMPUTER PREDICTIVE/PERF TOOLS	annual	3,000	0.3476	1,043	0	0	0	348	348	348
	26	PWEE	BOTTOM ASH CONTROLS REPL, U 4&5	2009	2,267	0.4800	1,088	0	0	64	1,024	0	0
	27	PWEE	UNALLOCATED FUTURE PROJECTS U4&5	annual	37,768	0.4800	18,129	0	0	553	6,000	5,069	6,506
					238,617		**113,609**	**4,098**	**14,218**	**19,986**	**24,157**	**34,062**	**17,090**

FOUR CORNERS CAPITAL FORECAST

Updated July 1, 2007

					100%			Overhauls:					
								Unit 4:	Minor (S)			Major (S)	
		Work		In	Share	SCE	SCE	Unit 5:		Major (S)			Minor (S)
	id	Order	Capital Project Description	Service	Total	Share	Total	Prior	2007	2008	2009	2010	2011
28	1	07-11	AIR PREHEATER H/C BASKET REPL, U 5	2008	2,000	0.4800	960	0	360	600	0	0	0
28	2	07-19	GEN PROT RELAY REPLACEMENT, U 5	2008	249	0.4800	120	0	46	73	0	0	0
28	3	PWEE	IP TURBINE BLADE REPLACEMENT, U 5	2008	1,200	0.4800	576	0	0	576	0	0	0
28	4	07-13	LP GENERATOR FIELD REWIND, U 5	2008	1,828	0.4800	877	0	346	532	0	0	0
28	5	PWEE	REHEAT ISOLATION VALVES, U 5	2008	225	0.4800	108	0	0	108	0	0	0
28	6	07-22	SUPERHEAT ATTEMPERATOR REPL, U 5	2008	185	0.4800	89	0	50	38	0	0	0
28	7	PWEE	FD FAN MOTOR REPL, U 4	2010	200	0.4800	96	0	0	0	0	96	0
28	8	PWEE	GEN PROT RELAY ADDITION, U 4	2010	267	0.4800	128	0	0	0	96	32	0
28	9	PWEE	IP TURBINE BLADE REPL, U 4	2010	200	0.4800	96	0	0	0	0	96	0
28	10	PWEE	LP GENERATOR REWEDGE, U 4	2010	235	0.4800	113	0	0	0	0	113	0
28	11	PWEE	LP TURBINE BLADE REPL, U 4	2010	435	0.4800	209	0	0	0	0	209	0
28	12	PWEE	REHEAT ISOLATION VALVES, U 4	2010	225	0.4800	108	0	0	0	0	108	0
28	13	PWEE	SBAC MOTOR REPL, U 4	2010	275	0.4800	132	0	0	0	0	132	0
28	14	07-21	AUX TURBINE OIL FILTRATION SYS, U 4&5	2007	220	0.4800	106	0	106	0	0	0	0
28	15	06-22R1	HYDROGEN GENERATOR INSTALLATION, U 4&5	2007	385	0.4800	185	114	70	0	0	0	0
28	16	07-25	MAIN TURBINE OIL FILTRATION SYSTEM, U 4	2007	120	0.4800	58	0	58	0	0	0	0
28	17	07-23	REDUND STATOR WATER FLOW MONITOR, U 4&5	2007	180	0.4800	86	0	86	0	0	0	0
28	18	PWEE	COAL SAMPLER CONTROLS REPL	2011	1,000	0.3476	348	0	0	0	0	0	348
28	19	PWEE	COAL HANDLING CONTROLS REPL, U 4&5	2011	1,500	0.4800	720	0	0	0	0	0	720
28	20	PWEE	COAL HANDLING REDUND PWR, PHASE II, U 4&5	2011	2,000	0.4800	960	0	0	0	0	0	960
28	21	06-14R1	COAL HNDLG REDUNDANT POWER SUPPL, U 4&5	2007	488	0.4800	234	0	234	0	0	0	0
28	22	06-10	MAIN FLAME SCANNER UPGRADE, U 4	2007	1,498	0.4800	719	357	362	0	0	0	0
28	23	PWEE	DCS ANALOG MASTER MODULE REPL, U 4	2010	2,000	0.4800	960	0	0	0	360	600	0
28	24	PWEE	DCS FIRMWARE UPGRADE	annual	989	0.3476	344	0	0	86	86	86	86
28	25	PWEE	DCS POWER SUPPLY REPL, U 4	2010	1,000	0.4800	480	0	0	0	144	336	0
28	26	07-32	FIBER OPTIC CABLE UPGRADE	annual	350	0.3476	122	0	41	42	39	0	0
28	27	PWEE	LAN SWITCH UPGRADE	annual	416	0.3476	145	0	0	0	45	50	50
28	28	07-40	AUX STEAM 3110B VALVE REPL, U 4	2007	285	0.4800	137	0	137	0	0	0	0
28	29	07-42	AUX STEAM 3110B VALVE REPL, U 5	2008	300	0.4800	144	0	0	144	0	0	0
28	30	PWEE	4KV SWITCHGEAR PROT RELAY REPL, U 4	2010	373	0.4800	179	0	0	0	99	80	0
28	31	06-18	ATB BREAKER REPL, 345KV SWYD	2007	2,335	0.1200	280	280	0	0	0	0	0
28	32	07-37	ATB BREAKER REPL, PHASE II, 345KV SWYD	2008	2,100	0.1200	252	0	120	132	0	0	0
28	33	07-39	FC1222 230 KV BREAKER, SWYD	2007	255	0.4800	122	0	122	0	0	0	0
28	34	07-38	FC556 & 652 500 KV BREAKER, SWYD	2008	1,200	0.3200	384	0	1	383	0	0	0
28	35	PWEE	SWITCHYARD RELIABILITY UPGRADE, U 4&5	annual	1,500	0.4800	720	0	0	0	240	240	240
28	36	PWEE	SWITCHYARD UPGRADES DUE TO BHP	2009	1,800	0.3476	626	0	0	0	626	0	0
28	37	PWEE	CONSTR TRANSFORMER SUBSTA REBUILD	2009	628	0.3476	218	0	0	0	218	0	0
28	38	07-17	RESERVE TRANSF BREAKER ADDITION, U 4&5	2007	367	0.4800	176	0	176	0	0	0	0
28	39	02-19R1	#4 XFMR T541 REPL, SWYD	2009	5,000	0.0346	173	0	0	0	173	0	0
28	40	07-41	345/500 KV XFMR BUSHING REPL	2007	1,325	0.4800	636	0	636	0	0	0	0
28	41	PWEE	345/230 KV XFMR BUSHING REPL, 230/345	2009	600	0.0346	21	0	0	0	21	0	0
28	42	PWEE	AUX TRANSFORMER SPARE, U 4&5	2009	850	0.4800	408	0	0	16	392	0	0
28	45	PWEE	RIVER STATION XFMR BUSHING REPL	2008	50	0.3476	17	0	0	17	0	0	0
28	46	PWEE	TYPE U XFMR BUSHING REPL, U 4&5	2008	700	0.4800	336	0	0	336	0	0	0
28	47	06-03	VEHICLE 2006 4C, 1/2 TON PICK-UP	2007	8	0.3476	3	0	3	0	0	0	0

FOUR CORNERS CAPITAL FORECAST
Updated July 1, 2007

	id	Work Order	Capital Project Description	In Service	100% Share Total	SCE Share	SCE Total	Overhauls: Unit 4: Unit 5: Prior	Minor (S) 2007	Major (S) 2008	2009	Major (S) 2010	Minor (S) 2011
28	48	07-02	NEW & REPL TOOLS, 2007	2007	150	0.3476	52	0	52	0	0	0	0
28	49	PWEE	NEW & REPL TOOLS, AFTER 2007	annual	600	0.3476	209	0	0	52	52	52	52
28	50	PWEE	OPERAT HANDHELD READER TOOL SYS	2008	405	0.3476	141	0	0	141	0	0	0
28	51	07-03	VEHICLE REPL, 2007	2007	204	0.3476	71	0	71	0	0	0	0
28	52	PWEE	VEHICLE REPL, AFTER 2007	annual	1,000	0.3476	348	0	0	87	87	87	87
28	53	05-06	AIR COMPRESSOR VSI, U 4&5	2007	461	0.4800	221	199	22	0	0	0	0
28	54	07-35	PBX UPGRADE	2007	100	0.3476	35	0	35	0	0	0	0
28	55	PWEE	WAN UPGRADE	2008	989	0.3476	344	0	0	344	0	0	0
28	56	PWEE	MICROWAVE/PHONE SYSTEM UPGRADE	2009	1,000	0.3476	348	0	0	0	348	0	0
28	57	03-04	TRAINING FACILITY	2007	684	0.3476	238	10	228	0	0	0	0
28	58	PWEE	U4&5 MAINTENANCE BUILDING UPGRADE	2011	2,000	0.3476	695	0	0	0	0	174	521
28	59	06-01	MISC CAP, ENGR ELECTRONIC FILING COMMON	2007	25	0.3476	9	0	9	0	0	0	0
28	60	07-18	BOILER MAINT TRACKING SOFTWARE, U 4&5	2008	353	0.4800	169	0	25	144	0	0	0
28	61	07-33	DATA HISTORIAN REPL	2007	347	0.3476	121	0	121	0	0	0	0
28	62	PWEE	ELECTRONIC DOCUMENTATION UPGRADE	annual	1,950	0.3476	678	0	0	0	226	226	226
28	63	07-31R0	MAXIMO SOFTWARE UPGRADE	2007	511	0.3476	178	0	178	0	0	0	0
28	64	PWEE	PERFORMANCE MONITORING SYSTEM	2008	911	0.3476	316	0	0	316	0	0	0
28	65	07-28	PLANT RTU REPLACEMENT, U 4&5	2007	80	0.4800	38	0	38	0	0	0	0
28	66	07-29	SMARTSIGNAL PRED COND MONITOR	2007	1,180	0.3476	410	174	237	0	0	0	0
28	67	07-20	STATOR LEAK MONITORING SYS, U 4&5	2007	220	0.4800	106	0	106	0	0	0	0
28	68	07-01	MISC CAP EXPEND, 2007 COMMON	2007	230	0.3476	80	0	80	0	0	0	0
28	69	07-24	B INDUCED DRAFT FAN VSI REPL, U 4&5	2007	171	0.4800	82	0	82	0	0	0	0
28	70	PWEE	SPARE CIRC WATER PUMP MOTOR, U 4&5	2009	500	0.4800	240	0	0	0	240	0	0
					53,415		**19,036**	**1,134**	**4,236**	**4,168**	**3,492**	**2,716**	**3,290**
			Reliability Total		**292,032**		**132,645**	**5,232**	**18,454**	**24,155**	**27,648**	**36,778**	**20,379**
	ENVIRONMENTAL												
	1	PWEE	OVERFIRE AIR NOX ABATEMENT U5	2009	8,000	0.4800	3,840	0	0	1,920	1,920	0	0
	2	PWEE	OVERFIRE AIR NOX ABATEMENT U4	2010	8,240	0.4800	3,955	0	0	51	589	3,315	0
	3	PWEE	DYNAMIC CLASSIFIER MODIFICATION, U 4	2010	6,420	0.4800	3,082	0	0	93	1,606	1,382	0
	4	PWEE	DYNAMIC CLASSIFIER MODIFICATION, U 5	2011	6,613	0.4800	3,174	0	0	0	95	1,655	1,424
	5	07-07R0	SO2 CONTROLS REPL, U 5	2008	4,939	0.4800	2,371	15	1,626	730	0	0	0
	6	PWEE	SO2 CONTROLS REPL, U 4	2010	2,333	0.4800	1,120	0	0	0	400	720	0
	7	PWEE	SCRUBBER OUTLET DUCT LINER REPL, U 4	2010	6,367	0.4800	3,056	0	0	16	1,600	1,440	0
	8	07-09	BAGHOUSE DUST SUPPRESSION, U 4&5	2008	2,356	0.4800	1,131	0	1,107	24	0	0	0
	9	07-10R0	BAGHOUSE TURNING VANES REPL, U 5	2008	2,204	0.4800	1,058	2	576	480	0	0	0
	10	06-20R2	ASH LANDFILL AND HAUL ROAD, U 4&5 Phase 1	2007	7,554	0.4800	3,626	90	3,536	0	0	0	0
	11	PWEE	DRY ASH LAND FILL, U 4&5 Phase 2	2011	5,000	0.4800	2,400	0	0	0	0	0	2,400
	12	PWEE	FLY ASH BENEFICIATION AREA IMPROV, U 4&5	2009	2,500	0.4800	1,200	0	0	0	1,200	0	0
	13	06-21	THICK UNDERFL TO LINED ASH IMPOUND, U 4-5	2007	3,406	0.4800	1,635	1,510	125	0	0	0	0
	14	PWEE	5268' LIFT LINED ASH IMPOUNDMENT, U 4-5	2011	3,529	0.4800	1,694	0	0	279	212	576	627
	15	PWEE	WASTE PROCESSING SYSTEM IMPROV, U 4&5	2009	2,500	0.4800	1,200	0	0	0	1,200	0	0
	16	PWEE	INTAKE STRUCTURE MODIFICATIONS, U 4&5	2008	3,000	0.4800	1,440	0	0	1,440	0	0	0
	17	PWEE	RIVER STATION 316B REG MODIF	2011	3,000	0.3476	1,043	0	0	0	0	0	1,043
					77,960		**37,024**	**1,617**	**6,969**	**5,032**	**8,823**	**9,088**	**5,494**

FOUR CORNERS CAPITAL FORECAST								Overhauls:					
Updated July 1, 2007					100%			Unit 4:	Minor (S)			Major (S)	
		Work		In	Share	SCE	SCE	Unit 5:		Major (S)			Minor (S)
	id	Order	Capital Project Description	Service	Total	Share	Total	Prior	2007	2008	2009	2010	2011
18	1	07-15	MERCURY CEMS, U 4&5	2008	1,033	0.4800	496	1	366	129	0	0	0
18	2	PWEE	SO2 PROCESS IMPROVEMENTS, U 4&5	2011	1,000	0.4800	480	0	0	0	0	96	384
18	3	06-11	STACK FLOW MEASUREMENT REPL, U 4&5	2007	672	0.4800	322	130	192	0	0	0	0
18	4	PWEE	BAGHOUSE MAINTENANCE BLDG, U 4&5	2008	373	0.4800	179	0	0	179	0	0	0
18	5	PWEE	ABSORBER MODULE BLOW DOWN MODIF, U4	2008	267	0.4800	128	0	0	128	0	0	0
18	6	PWEE	ABSORBER MODULE BLOW DOWN MODIF, U5	2010	267	0.4800	128	0	0	0	0	128	0
18	7	PWEE	U4&5 SO2 CONTROL BUILDING REMODEL	2011	250	0.3476	87	0	0	0	0	0	87
18	8	PWEE	DEW POINT MONITORING EQUIP REPL, U 4&5	2009	133	0.4800	64	0	0	0	64	0	0
18	9	07-36	EPA EDR SOFTWARE UPGRADE	2007	57	0.3476	20	0	20	0	0	0	0
18	10	PWEE	HUMATE SILO & SLAKING EQUIP, U 4&5	2009	1,000	0.4800	480	0	0	0	480	0	0
18	11	07-14	WASTE PROCESSING CONTROLS REPL, U 4&5	2007	1,676	0.4800	804	5	799	0	0	0	0
18	12	PWEE	ASH POND 6 CLOSURES	annual	140	0.3476	48	0	0	16	11	11	11
18	13	07-12R0	5258' LIFT LINED ASH IMPOUNDMENT, U 4&5	2009	1,861	0.4800	893	0	356	288	250	0	0
18	14	PWEE	THICKENER AUTOMATIC POLYMER INJECT, U 4&5	2009	200	0.4800	96	0	0	0	96	0	0
18	15	PWEE	HYDROBIN AREA UPGRADE, U 4&5	2009	800	0.4800	384	0	0	192	192	0	0
18	16	PWEE	NPDES HAUL ACCESS ROAD	2008	791	0.3476	275	0	0	275	0	0	0
18	17	07-30	POND CHLORIDES CONTROL UPGRADES	2008	748	0.3476	260	0	17	243	0	0	0
18	18	PWEE	NPDES DECANT CELL UPGRADES	2010	593	0.3476	206	0	0	0	103	103	0
18	19	PWEE	500KV YARD STEP-UP TRANSF OIL BERM, U 4&5	2008	120	0.4800	58	0	0	58	0	0	0
18	20	07-26	SPCC CONTAIN OF OIL TANKS, U 4&5	2007	91	0.4800	44	0	44	0	0	0	0
					12,071		**5,453**	**137**	**1,793**	**1,508**	**1,196**	**338**	**482**
			Environmental Total		**90,031**		**42,476**	**1,754**	**8,762**	**6,540**	**10,018**	**9,426**	**5,976**
	SAFEETY												
	1	PWEE	PLANT FIRE WTR UNDGRND PIPE REPL	annual	3,000	0.3476	1,043	0	0	70	521	452	0
	2	PWEE	POTABLE WATER SYSTEM REPL	2011	3,000	0.3476	1,043	0	0	0	0	0	1,043
					6,000		**2,086**	**0**	**0**	**70**	**521**	**452**	**1,043**
	3	05-05R1	GSU & AUX XFMR FIRE WALL/OIL CONTAIN, U 4&5	2007	1,589	0.4800	763	535	227	0	0	0	0
	4	PWEE	HIGH ENERGY PIPING, U 4	2010	1,000	0.4800	480	0	0	0	48	432	0
	5	07-34	LAYDOWN YARD LIGHTING	2007	289	0.3476	100	2	98	0	0	0	0
	6	07-27	COLD REHEAT #2 PIPE SUPPORT, U 5	2008	89	0.4800	43	0	12	30	0	0	0
					2,967		**1,386**	**537**	**338**	**30**	**48**	**432**	**0**
			Safety Total		**8,967**		**3,471**	**537**	**338**	**100**	**569**	**884**	**1,043**
			TOTAL		**391,030**		**178,593**	**7,523**	**27,554**	**30,794**	**38,236**	**47,088**	**27,398**

Appendix C

Co-Tenancy Agreement

CO-TENANCY AGREEMENT

BETWEEN

ARIZONA PUBLIC SERVICE COMPANY

EL PASO ELECTRIC COMPANY

PUBLIC SERVICE COMPANY OF NEW MEXICO

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT
AND POWER DISTRICT

SOUTHERN CALIFORNIA EDISON COMPANY

TUCSON GAS & ELECTRIC COMPANY

In the event it is determined by arbitration, pursuant to the provisions of this Co-Tenancy Agreement or otherwise, that the protesting Participant is entitled to a refund of all or any portion of a disputed payment or payments, or is entitled to the reasonable equivalent in money of non-monetary performance of a disputed obligation theretofore made, then, upon such determination, the non-protesting Participants shall pay such amount to the protesting Participant, together with interest thereon at the rate of six per cent (6%) per annum from the date of payment or of the performance of a disputed obligation to the date of reimbursement. Reimbursement of the amount so paid shall be made by the non-protesting Participants in the ratio of their respective capacity entitlements to the total capacity entitlement of all non-protesting Participants.

20.5 In the event a default by any Participant in the payment or performance of any obligation under the Project Agreements shall continue for a period of six (6) months or more without having been cured by the defaulting Participant or without such Participant having commenced and continued action in good faith to cure such default, or in the event the question of whether an act of default exists is the subject of arbitration and such default continues for a period of six (6) months following a final determination by the arbitrators (or a Court of competent jurisdiction as provided in Section 19.9 hereof) that an act of default exists and the defaulting

Participant has failed to cure such default or to commence such action during said six (6) month period, then, at any time thereafter and while said default is continuing, all of the non-defaulting Participants may, by written notice to all Participants, suspend the right of the defaulting Participant to receive all or a part of its capacity entitlement by reducing the amount of energy generation of the Four Corners Project by a part or all of the capacity entitlement of the defaulting Participant, in which event:

20.5.1 The non-defaulting Participants shall instruct the Operating Agent in writing to suspend and the Operating Agent shall thereupon suspend, delivery of all or the specified part of the defaulting Participant's capacity entitlement.

20.5.2 During the period that such decrease in generation is in effect, the non-defaulting Participants shall bear all of the operation and maintenance costs, fuel costs, insurance costs and other expenses otherwise payable by the defaulting Participant under the Operating Agreement in the ratio of their respective capacity entitlements to the total capacity entitlements of all non-defaulting Participants.

20.5.3 The defaulting Participant shall be liable to the non-defaulting Participants (in the proportion that the capacity entitlement of each non-defaulting Participant bears to the capacity entitlements of all non-defaulting Participants) for all costs incurred by such non-defaulting Participants pursuant to Section 20.5.2 hereof and for all excess costs and expenses involved in operating the Four Corners Project at a reduced level of generation brought about by the reduction of the capacity entitlement of the defaulting Participant. The proceeds paid by any defaulting Participant to remedy any such default shall be distributed to the non-defaulting Participants in the ratio of their respective capacity entitlements to the total capacity entitlements of all non-defaulting Participants.

20.6 No waiver by a Participant of its rights with respect to a default under this Co-Tenancy Agreement, or with respect to any other matter arising in connection with this Co-Tenancy Agreement, shall be effective unless all non-defaulting Participants waive their respective rights and any such waiver shall not be deemed to be a waiver with respect to any subsequent default or matter. No delay, short of the statutory period of limitations, in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

20.7 The rights and remedies provided in this Co-Tenancy Agreement shall be in addition to the rights and remedies of the Participants as set forth and contained in any other of the Project Agreements.

Exhibit D

20.6 No waiver by a Participant of its rights with respect to a default under this Co-Tenancy Agreement, or with respect to any other matter arising in connection with this Co-Tenancy Agreement, shall be effective unless all non-defaulting Participants waive their respective rights and any such waiver shall not be deemed to be a waiver with respect to any subsequent default or matter. No delay, short of the statutory period of limitations, in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

20.7 The rights and remedies provided in this Co-Tenancy Agreement shall be in addition to the rights and remedies of the Participants as set forth and contained in any other of the Project Agreements.

21. TERM:

21.1 This Co-Tenancy Agreement shall continue in force and effect for a period of fifty (50) years from the effective date and time of this Co-Tenancy Agreement.

22. RELATIONSHIP OF PARTIES:

22.1 The duties, obligations and liabilities of the Participants hereto are intended to be several and not joint or collective, and nothing herein contained shall ever be construed to create an association, joint venture, trust or partnership, or impose a trust or partnership duty, obligation or liability on or with regard to any one or more of the Participants hereto. Each Participant hereto shall be individually responsible for its own obligations as herein provided. No Participant or group of Participants shall be under the control of or shall be deemed to control any other Participant or the Participants as a group. No Participant shall have a right or power to bind any other Participant(s) without its or their express written consent, except as expressly provided in this Co-Tenancy Agreement, the Construction Agreement or the Operating Agreement.

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of PETITION FOR MODIFICATION OF DECISION NO. 07-01-039 OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) on all parties identified on the attached service list(s). Service was effected by one or more means indicated below:

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **28th day of January, 2008**, at Rosemead, California.

/s/RAQUEL IPPOLITI
Raquel Ippoliti
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